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W3F1-2016-0069

November 10, 2016

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

SUBJECT: Responses to Request for Additional Information Set 2 Regarding the License Renewal Application for Waterford Steam Electric Station, Unit 3 (Waterford 3)
Docket No. 50-382
License No. NPF-38

REFERENCES:

1. Entergy letter W3F1-2016-0012 "License Renewal Application, Waterford Steam Electric Station, Unit 3" dated March 23, 2016.
2. NRC letter to Entergy "Requests for Additional Information for the Review of the Waterford Steam Electric Station, Unit 3, License Renewal Application – Set 2, dated October 12, 2016.

Dear Sir or Madam:

By letter dated March 23, 2016, Entergy Operations, Inc. (Entergy) submitted a license renewal application (Reference 1).

In letter dated October 12, 2016 (Reference 2), the NRC staff made a Request for Additional Information (RAI) Set 2, needed to complete its review. Enclosure 1 provides the responses to the Set 2 RAIs. Also, Enclosure 2 contains a material designation correction for an entry in Table 3.4.2-4 of Reference 1.

There are no new regulatory commitments contained in this submittal. If you require additional information, please contact the Regulatory Assurance Manager, John Jarrell, at 504-739-6685.

I declare under penalty of perjury that the foregoing is true and correct. Executed on November 10, 2016.

Sincerely,

MRC/AJH

Enclosures:

1. Set 2 RAI Responses – Waterford 3 License Renewal Application
2. Table 3.4.2-4 Correction

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Enclosure 1 to

W3F1-2016-0069

Set 2 RAI Responses
Waterford 3 License Renewal Application

RAI B.1.13-1

Background:

LRA Section B.1.13, Exception No. 5, states that cross-hatch testing, as described in ASTM D 3359, “Standard Test Methods for Measuring Adhesion by Tape Test,” is not conducted when signs of pitting, corrosion, or failure of the coating are detected. The basis for the exception, in part, includes crediting spot wet sponge tests and dry film testing as a means to detect coating adhesion deficiencies.

Issue:

While the staff recognizes that wet sponge tests will detect coating holidays and dry film testing detects the thickness of a coating; however, it is not clear to the staff that these tests will provide sufficient insights related to adhesion of coatings. The staff recognizes that the footnote for Exception No. 5 and Enhancement No. 21 cite other methods that effectively detect coating adhesion deficiencies in low flow tank locations (e.g., Society of Protective Coatings cleaning specifications, lightly tapping the coating, ASTM D4541,“Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers”).

Request:

State the basis for why spot wet sponge tests and dry film testing are effective means to identify coating adhesion deficiencies.

Waterford 3 Response

The wet sponge and dry film testing referenced in Exception Note 5, and in Enhancements 18 and 21, are intended to detect coating deficiencies including holidays and coating thickness issues rather than the quality or degree of coating adhesion. Because Exception 5 is specific to testing for coating adhesion, the references to wet sponge tests, dry film testing, and thickness measurements of corroded areas are removed from Exception Note 5. Wet sponge and dry film testing remain as specified in Enhancements 18 and 21.

The LRA Section B.1.13 Exception Note 5 is revised as shown below. Additions are shown with underline and deletions with strikethrough.

LRA B.1.13 FIRE WATER SYSTEM

Exception Note 5

Cross hatch testing is a destructive test. WF3 performs a visual inspection of the fire water tank interior coating every 5 years. RG 1.54 describes the use of ASTM test standard D4541-09, "Pull-Off Strength of Coatings Using Portable Adhesion Testers," as an acceptable alternative method for performing adhesion testing of coatings on metal substrates using a fixed-alignment adhesion tester. In addition, lightly tapping, scraping or cleaning the degraded area per Society of Protective Coatings (SSPC) SSPC-SP2, Hand Tool Cleaning; SSPC-SP3, Power Tool Cleaning; SSPC-SP11, Cleaning of Bare Metal; and SSPC-SP WJ-1, 2, 3 and 4, Water Jet Cleaning, allow a qualified inspector and design engineering the ability to determine the extent of peeling, delamination and blistering to ensure that downstream flow blockage and tank integrity are not an issue. ~~Ultrasonic thickness measurement where there is evidence of pitting or corrosion ensures the tank thickness is sufficient to perform its pressure boundary function. WF3 will perform spot wet sponge tests and dry film testing to identify coating adhesion deficiencies. When indications are identified in the fire water tank coating, WF3 performs an evaluation to ensure the tank can perform its function until the next inspection. In addition, WF3 performs ultrasonic thickness checks or mechanical measurements of any identified corroded areas.~~

RAI B.1.13-2

Background:

LRA Section B.1.13, Exception No. 6, addresses trip testing preaction valves with the control valves cracked open in lieu of testing with control valves in the full open position. Enhancement No. 3 addresses internal inspections of dry sprinkler piping downstream of preaction systems.

Issue:

Exception No. 6 and Enhancement No.3 are jointly addressed in this RAI because they both address inspections or tests that are used to detect potential flow blockage of dry sprinkler piping downstream of preaction systems. GALL Report AMP XI.M27, "Fire Water System," as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," recommends (by citing NFPA 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," Section 13.4.3.2.2) that preaction systems be tested with the control valve in the full open position. The staff's concern with Exception No. 6 is that a cracked open control valve might not provide adequate flow to detect potential flow blockage. The staff recognizes that a sufficient number of internal pipe inspections of dry piping downstream of preaction valves, as cited in Enhancement No. 3, could be an effective alternative to testing the control valves in the full open position. However, the enhancement does not state: (a) the frequency of inspections; (b) how access to the piping will be obtained (e.g., removal of a sprinkler and opening a flushing connection); and (c) the location of the removed sprinkler (i.e., most remote).

Request:

State and justify the basis for why flow rates sufficient to detect flow blockage will be achieved during preaction valve testing with the control valve cracked open. In regard to the internal visual inspections of dry piping downstream of preaction systems, state: (a) the frequency of inspections; (b) how access to the piping will be obtained (e.g., removal of a sprinkler and opening a flushing connection); and (c) the location of the removed sprinkler (i.e., most remote).

Waterford 3 Response

Exception No. 6 incorrectly stated the preaction valves are trip tested. An enhancement is added to the program to perform trip testing of the preaction valves, however, the trip testing will be performed with the manual isolation valve closed. Entergy performs a drain test every 18 months on each in-scope preaction system. The drain test is performed with the manual isolation valve open and the preaction valve closed by opening a drain valve just upstream of the preaction valve and verifying there is adequate flow. The drain test provides for adequate flow to determine whether there is flow blockage upstream of the preaction valve. As described in LRA Section B.1.13, Enhancement 3, internal inspections of the dry portions of the preaction system downstream of the preaction valve will be performed to identify any flow obstructions or blockage of piping or sprinkler heads that could prevent the system from performing its intended function.

For both Enhancement 3 and Enhancement 4, the inspections will be performed at least once every 5 years. Access for the inspections is gained by opening a flushing connection and removing the most remote sprinkler head.

LRA Sections A.1.13 and B.1.13 are revised as shown below. Additions are shown with underline and deletions with strikethrough.

A.1.13 Fire Water System Program

- Revise Fire Water System Program procedures to perform an internal inspection every five years for evidence of loss of material and the presence of foreign organic or inorganic material that could result in flow obstructions or blockage of a sprinkler head of the dry piping downstream of preaction ~~systems~~ valves. The inspection shall be performed by opening a flushing connection, removing the most remote sprinkler head, and using a method ~~used shall be~~ capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion, corrosion product deposition, and flow blockage due to fouling.
- Revise Fire Water System Program procedures to perform an internal inspection every five years for evidence of loss of material and the presence of foreign organic or inorganic material that could result in flow obstructions or blockage of a sprinkler head of the dry piping downstream of the automatic deluge ~~systems~~ valves. The inspection shall be performed by opening a flushing connection, removing the most remote sprinkler head, and using a method ~~used shall be~~ capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion, corrosion product deposition, and flow blockage due to fouling.
- Revise the Fire Water System Program procedures to perform preaction valve trip testing every three years with the manual isolation valve closed.

B.1.13 FIRE WATER SYSTEM

Exception No. 6

NFPA 25 Section 13.4.3.2.3 requires preaction valves to be trip tested every 3 years with the control (manual isolation) valve fully open. ~~WF3 trip tests the preaction valves with the control valves cracked open~~ WF3 will perform the trip test every three years with the manual isolation valve closed.[6]

Exception Note 6.

Trip testing the preaction valves with the ~~control~~ manual isolation valve open would allow fire water to enter the portion of the system that is designed to be dry. In addition, there is a potential for wetting down equipment critical to normal and shut down operations. ~~Because the preaction system has closed sprinkler heads and supervisory air it is unlikely that operations would not be aware of a leaking closed sprinkler head.~~ Flow testing upstream of the preaction valve is performed every 18 months with the preaction valve closed, the manual isolation valve open and a drain valve just upstream of the preaction valve open. The internal inspections described in Enhancement 3 will monitor for foreign material that could block flow. The combination of flow testing upstream of the preaction valve and visual inspection of the piping downstream of the preaction valve provide reasonable assurance that any flow blockage in the preaction system would be detected before it could render the system unable to perform its intended function.

Enhancements

4. Detection of Aging Effect	Revise Fire Water System Program procedures to perform an internal inspection every five years for evidence of loss of material and the presence of foreign organic or inorganic material that could result in flow obstructions or blockage of a sprinkler head of the dry piping downstream of preaction ~~systems~~ valves. The inspection shall be performed by opening a flushing connection, removing the most remote sprinkler head, and using a method ~~used shall be~~ capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion, corrosion product deposition, and flow blockage due to fouling.
4. Detection of Aging Effect	Revise Fire Water System Program procedures to perform an internal inspection every five years for evidence of loss of material and the presence of foreign organic or inorganic material that could result in flow obstructions or blockage of a sprinkler head of the dry piping downstream of the automatic deluge ~~systems~~ valves. The inspection shall be performed by opening a flushing connection, removing the most remote sprinkler head, and using a method ~~used shall be~~ capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion, corrosion product deposition, and flow blockage due to fouling.
4. Detection of Aging Effect	Revise the Fire Water System Program procedures to perform preaction valve trip testing every three years with the manual isolation valve closed.

RAI B.1.13-3

Background:

The LRA Section B.1.13 states several enhancements (Enhancement Nos. 2, 7, 14, 16, 19, and 20) to the "detection of aging effects" program element of the Fire Water System program.

a. Enhancement No. 2 states that a wet pipe sprinkler system will be inspected every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line.
b. Enhancement No. 7 states that strainers will be removed every 5 years to clean and inspect for damage and corroded parts.
c. Enhancement No. 16 states that vacuum box testing will be performed on the bottom of the fire water storage tanks to identify leaks, and in the event the bottom of the fire water tank is uneven, the station will perform a suitable NDE technique rather than vacuum box testing to identify leaks.
d. Enhancement 19 states that augmented flow tests or flushing and wall thickness measurements will be conducted for fire water piping experiencing recurring internal corrosion.
e. Enhancement No. 20 states that alternative actions will be taken prior to returning a fire water storage tank to service without repair or replacement of degraded coatings.

Issue:

a. NFPA 25 Sections 14.2.2 (as cited in AMP XI.M27, as modified by LR-ISG-2012-02) and Section A.14.2.2 require that each building's wet pipe system be inspected every 5 years. During the audit, the staff verified that there is only one wet pipe sprinkler system in each protected building. Enhancement No. 2 does not state that the wet pipe systems in each building will be inspected every 5 years.
b. AMP XI.M27, as modified by LR-ISG-2012-02, recommends that strainer inspections be conducted every refueling outage interval or when the system has been actuated. The staff also noted that NFPA 25 Section 10.2.1.7 states that mainline strainers are inspected every 5 years as stated in the enhancement. Subsequent to the issuance of LR-ISG-2012-02, the staff concluded that absent flow in the system, an inspection would not provide an effective indicator of potential flow blockage in the system; however, several actuations of a system could occur during any given 5-year period. The LRA does not state that the strainers will be inspected after every actuation.
c. The staff noted that vacuum box testing is consistent with NFPA 25 Section 9.2.7 (6); however, the staff lacks sufficient detail to evaluate, "a suitable NDE technique."
d. Enhancement No.19 does not address whether wall thickness measurements will be conducted in addition to flow tests and flushes or in addition to only flushes. The enhancement did not state several considerations for managing recurring internal corrosion as cited in SRP-LR Section 3.3.2.2.8 (e.g., number of inspections, criteria for additional inspections). In addition, there is an inconsistency between LRA Section 3.3.2.2.8, "Loss of Material due to Recurring Internal Corrosion," which states that inspections will occur on a refueling outage interval and Enhancement 19, which states that inspections will be conducted every 5 years.
e. The "acceptance criteria" program element of GALL Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," recommends that blister size and frequency should not be increasing between inspections. The acceptance criteria also recommends that a coatings specialist evaluate blisters. Enhancement

No. 20 would permit the alternative return-to-service actions to be used even though the size and frequency of blisters could be increasing; and the enhancement allows a coating inspector rather than a coating specialist to evaluate the conditions for use of the alternative.

Request:

a. State whether each building's wet pipe system will be inspected every 5 years. If each building's wet pipe system will not be inspected every 5 years, state the basis for why there will be adequate inspections of the wet pipe systems to detect potential degradation (e.g., loss of material, flow blockage).

b. State whether strainers will be inspected whenever the system has been actuated or state the basis for why inspecting the strainers every 5 years regardless of the number of times the system is actuated will be effective in detecting potential flow blockage.

c. State the specific techniques that will be used as an alternative to vacuum box testing.

d. State whether wall thickness measurements will be conducted in addition to flow tests and flushes or in addition to only flushes.

   State: (a) the minimum number of inspections that will occur in each 5-year interval; (b) the criteria to be used to determine that additional inspections are warranted (e.g., extent of degradation at individual corrosion sites, rate of degradation change, trend of through-wall leaks); (c) how inspections of components that are not easily accessed will be conducted; (d) how leaks in buried or underground piping will be detected; and (e) how many additional inspections will be conducted within an inspection interval when through-wall leakage is detected or inspection results reveal pipe wall thickness below minimum wall.

   State whether inspections will be conducted every 18 months or every 5 years and correct the internal inconsistency between LRA Section 3.3.2.2.8 and Enhancement No.19.

e. State the basis for using: (a) the return-to-service alternative even though the size and frequency of blisters could be increasing; and (b) a coating inspector rather than a coating specialist to evaluate the conditions for use of the alternative.

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Waterford 3 Response

a. There is one in-scope wet pipe system in each building and each building's wet pipe system will be inspected every five years. LRA Sections A.1.13 and B.1.13 Enhancement 3 are clarified as shown below. Additions are underlined and deletions are shown with strikethrough.

A.1.13 Fire Water System

Enhancement 2

- Revise Fire Water System Program procedures to perform an inspection of each building's wet pipe fire water system ~~piping condition~~ every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic or inorganic material that could result in flow obstructions or blockage of a sprinkler head. The inspection method used shall be capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion, corrosion product deposition, and flow blockage due to fouling. Ensure procedures require a follow-up volumetric wall thickness evaluation where irregularities are detected.

B.1.13 FIRE WATER SYSTEM

Enhancement 2

4. Detection of Aging Effects	Revise Fire Water System Program procedures to perform an inspection of each building's wet pipe fire water system ~~piping condition~~ every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic or inorganic material that could result in flow obstructions or blockage of a sprinkler head. The inspection method used shall be capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion, corrosion product deposition, and flow blockage due to fouling. Ensure procedures require a follow-up volumetric wall thickness evaluation where irregularities are detected.

b. Mainline strainers will be inspected every five years and after each actuation. LRA Sections A.1.13 and B.1.13 Enhancement 7 are revised as shown below. Additions are underlined.

A.1.13 Fire Water System

Enhancement 7

- Revise Fire Water System Program procedures to remove strainers every 5 years and after each actuation to clean and inspect for damage and corroded parts.

B.1.13 FIRE WATER SYSTEM

Enhancement 7

4. Detection of Aging Effects	Revise Fire Water System Program procedures to remove strainers every 5 years and after each actuation to clean and inspect for damage and corroded parts.

c. As described in LRA Section A.1.13 and B.1.13 Enhancement 16, vacuum box testing or a suitable NDE technique will be used to detect leaks in the bottom of the fire water tanks. Enhanced visual testing (EVT) -1 and ultrasonic testing are examples of suitable techniques to detect leaks in the bottom of the fire water system tank. Vacuum box testing or other suitable NDE techniques, continuously monitoring fire water tank level with instrumentation that alarms in the control room, and routine operator observations of the tank and its surrounding area provide reasonable assurance that a leak in the bottom of a tank will be detected before a fire water tank become unable to perform its intended function.

d. As described in LRA Section A.1.13 and B.1.13 Enhancement 19, wall thickness measurements will be performed in addition to flow tests and flushes. The enhancement is revised to clarify this intent.

The internal inconsistency between LRA Section 3.3.2.2.8 and Enhancement 19 is eliminated in the revision of Enhancement 19 below. The number of inspections to be performed to address recurring internal corrosion (RIC) during each refueling cycle until the RIC has subsided is based on an evaluation under the corrective action program of what is needed to characterize the issue considering the material, environment and aging mechanisms to ensure the system can perform its intended function. The criteria used to determine that additional inspections are warranted consist of extent of condition, rate of degradation based on the change from previous inspections, and trend of overall system health. The evaluation of inaccessible areas in any system is based on the inspection of accessible areas. Leaks in the fire water system, including underground leaks, are detected by system walkdowns, monitoring jockey pump operating time, and monitoring fire water tank level via alarm in the control room. As mentioned above the number of additional inspections to address through-wall leakage or wall thickness below minimum wall within an inspection interval is based on the information needed to ensure the system can perform its intended function until the next scheduled inspection.

The enhanced fire water system aging management program and augmented inspections as described in LRA B.1.13 provide reasonable assurance that the system will perform its intended function.

LRA Sections A.1.13 and B.1.13 Enhancement 19 are revised as shown below. Additions are shown with underline and deletions with strikethrough.

A.1.13 Fire Water System Program

Enhancement 19

- Revise Fire Water System Program procedures to conduct <u>1)</u> augmented flow tests or flushing<u>,</u> and <u>2)</u> wall thickness measurements for fire water piping experiencing recurring internal corrosion prior to the period of extended operation and at least once every ~~5 years~~<u>refueling cycle </u>during the period of extended operation<u> until the recurring internal corrosion condition has been corrected</u>. Procedures shall be revised to require wall thickness measurements at selected locations that provide a representative sample of the type of piping and environment where the recurring corrosion is occurring. The procedure should allow for selected grid locations to change based on the relevance and usefulness of the wall thickness measurements.

B.1.13 FIRE WATER SYSTEM

Enhancement 19

4. Detection of Aging Effect	Revise Fire Water System Program procedures to conduct 1) augmented flow tests or flushing, and 2) wall thickness measurements for fire water piping experiencing recurring internal corrosion prior to the period of extended operation and at least once every ~~5 years~~refueling cycle during the period of extended operation until the recurring internal corrosion condition has been corrected. Procedures shall be revised to require wall thickness measurements at selected locations that provide a representative sample of the type of piping and environment where the recurring corrosion is occurring. The procedure should allow for selected grid locations to change based on the relevance and usefulness of the wall thickness measurements.

e. LRA Sections A.1.13 and B.1.13 Enhancement 20 are revised as shown below. Additions are shown with underline and deletions with strikethrough.

A.1.13 Fire Water System Program

Enhancement 20

Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination or peeling unless there are only a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating specialist~~inspector~~, or the following actions are performed:

- Any blistering in excess of a few small intact blisters that are not growing in size or number, or blistering not completely surrounded by coating bonded to the substrate is removed.
- Any delaminated or peeled coating is removed.
- The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations.
- The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area

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- Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements.
- An evaluation is performed to ensure downstream flow blockage is not a concern.
- A follow-up inspection is scheduled to be performed within two years and every two years after that until the coating is repaired, replaced, or removed.

B.1.13 FIRE WATER SYSTEM

Enhancement 20

4. Detection of Aging Effect	Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination or peeling unless there are only a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating specialist~~inspector~~, or the following actions are performed: • Any blistering in excess of a few small intact blisters that are not growing in size or number, or blistering not completely surrounded by coating bonded to the substrate is removed. • Any delaminated or peeled coating is removed. • The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations. • The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area. • Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements. • An evaluation is performed to ensure downstream flow blockage is not a concern. • A follow-up inspection is scheduled to be performed within two years and every two years after that until the coating is repaired, replaced, or removed.

RAI B.1.13-4

Background:

LRA Section B.1.13, Enhancement No. 22, in the acceptance criteria program element states that adhesion results can be quantified by conducting visual inspections, wet sponge testing, or dry film testing.

Issue:

It is not clear to the staff that visual inspections, wet sponge testing, or dry film testing methods are capable of quantifying adhesion results.

Request:

State what method(s) will be used to quantify adhesion results.

Waterford 3 Response

The methods used to quantify coating adhesion are adhesion testing methods endorsed by Regulatory Guide 1.54. The last bullet of LRA Sections A.1.13 and B.1.13, Enhancement 22, is revised as shown below. Additions are underlined and deletions are shown with strikethrough.

LRA Section A.1.13, Fire Water System

Enhancement 22 last bullet

- When conducting adhesion testing, results meet or exceed the degree of adhesion recommended in plant-specific design requirements specific to the coating/lining and substrate. ~~Quantify the ability of the coating adhesion to meet the plant-specific design requirements specific to the coating/lining substrate for the fire water tanks based on visual inspections, wet sponge testing, or dry film testing~~.

LRA Section B.1.13, FIRE WATER SYSEM

Enhancement #22

6. Acceptance Criteria	Revise Fire Water System Program procedures to include acceptance criteria for the fire water tanks' interior coating that include: • When conducting adhesion testing, results meet or exceed the degree of adhesion recommended in plant-specific design requirements specific to the coating/lining and substrate. ~~Quantify the ability of the coating adhesion to meet the plant-specific design requirements specific to the coating/lining substrate for the fire water tanks based on visual inspections, wet sponge testing, or dry film testing~~.

RAI B.1.13-5

Background:

LRA Section B.1.13, Enhancement No. 25, in the corrective actions program element states that obstruction evaluations will be conducted if there is evidence of "excessive" discharge of material during routine flow tests.

Issue:

AMP XI.M27, as modified by LR-ISG-2012-02, recommends the use of the criteria in NFPA 25 Section 14.3, "Obstruction Investigation and Prevention," which uses the term "obstructive" rather than "excessive." The staff's concern is that the term "excessive" is not defined.

Request:

State the criteria for determining that the presence of material in the discharge from flow tests is excessive.

Waterford 3 Response

Obstructive material in the discharge of flow tests is a criterion for determining when an obstruction evaluation should be performed. Enhancement 25 in LRA Sections A.1.13 and B.1.13 is revised as shown below. Additions are shown with underline and deletions with strikethrough.

LRA Section A.1.13, Fire Water System

Enhancement 25

- Revise Fire Water System Program procedures to perform an obstruction evaluation if any of the following conditions exist:
  - There is an obstructive~~excessive~~ discharge of material during routine flow tests.

LRA Section B.1.13, FIRE WATER SYSEM

Enhancement 25 first bullet

7. Corrective Action	Revise Fire Water System Program procedures to perform an obstruction evaluation if any of the following conditions exist: • There is an obstructive~~excessive~~ discharge of material during routine flow tests.

RAI B.1.13-6

Background:

The staff reviewed FSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1 of LR-ISG-2012-02 and noted that certain aspects of the recommended FSAR Supplement content were not included.

Issue:

The licensing basis for this program for the period of extended operation may not be adequate if this information is not incorporated into the FSAR supplement for the Fire Water System program.

Request:

State the basis for not including the following in the FSAR supplement: (a) the program manages the aging effects through the use of flow testing and visual inspections performed in accordance with the 2011 Edition of NFPA 25; and (b) the water-based fire protection system is monitored such that loss of system pressure is immediately detected and corrective actions initiated. Alternatively, revise LRA Section A.1.13 to include the above aspects.

Waterford 3 Response

The first paragraphs of LRA Sections A.1.13 and B.1.13 are revised as shown below. Additions are underlined.

LRA Section A.1.13 Fire Water System

First Paragraph

The Fire Water System Program manages loss of material, flow blockage due to fouling, and loss of coating integrity for in-scope long-lived passive water-based fire suppression system components using periodic flow testing and visual inspections in accordance with NFPA 25 (2011 Edition). In addition, the fire water system pressure is monitored such that a loss of system pressure is immediately detected and corrective action is initiated. When visual inspections are used to detect loss of material and fouling, the inspection technique is capable of detecting surface irregularities that could indicate wall loss due to corrosion, corrosion product deposition, and flow blockage due to fouling.

LRA Section B.1.13 FIRE WATER SYSTEM

Program Description

First paragraph

The Fire Water System Program manages loss of material, flow blockage due to fouling, and loss of coating integrity for in-scope long-lived passive water-based fire suppression system components using periodic flow testing and visual inspections in accordance with NFPA 25 (2011 Edition). In addition, the fire water system pressure is monitored such that a loss of system pressure is immediately detected and corrective action is initiated. When visual inspections are used to detect loss of material and fouling, the inspection technique is capable of detecting surface irregularities that could indicate wall loss due to corrosion, corrosion product deposition, and flow blockage due to fouling.

RAI 3.3.1-1 (FWS AMR-1)

Background:

LRA Table 3.3.1, item 3.3.1-64 addresses copper alloy heat exchanger tubes. Loss of material due to general, pitting, and crevice corrosion will be managed by the Fire Water System program for these components.

Issue:

The staff recognizes that visual inspections can be capable of detecting pitting and crevice corrosion in heat exchanger tubes. However, copper alloy materials exposed to raw water are also susceptible to loss of material due to general corrosion. It is not clear to the staff how visual inspections will effectively detect general corrosion in heat exchanger tubes when the corrosion is uniform.

Request:

State and justify the method that will be used in the Fire Water System program to detect loss of material due to general corrosion in copper alloy tubes exposed to raw water.

Waterford 3 Response

The copper alloy tubes exposed to raw water are the tubes in the heat exchangers for the fire water diesel coolant systems. Item 64 of NUREG-1800 Table 3.3-1 includes steel in addition to copper alloy components. Steel is susceptible to general corrosion; however, general corrosion is not expected in copper alloy tubes exposed to raw water in the fire water system. At Waterford 3, raw water in the fire water storage tanks is supplied from the potable water system. This conclusion is supported by NUREG-1800, Table 3.3-1, Item 93, which does not identify general corrosion as an aging mechanism for copper alloy components exposed to raw water (potable). Therefore, a method of detection for loss of material due to general corrosion for copper alloy in raw water (potable) is not necessary.

RAI 3.3.1-2 (FWS AMR-2)

Background:

The Fire Water System program, as well as the FSAR supplement for the program, cite flow blockage due to fouling as an applicable aging effect.

Issue:

The LRA Table 2s and the “Discussion” section of LRA Table 3.3-1 associated with LRA Table 3.3.1, item 3.3.1-64, as well as other Table 3.3.1 items (i.e., 3.3.1-66, 3.3.1-130, 3.3.1-131, 3.3.1-136) do not address flow blockage due to fouling.

Request:

State whether flow blockage due to fouling will be managed for components cited in LRA Table 3.3.1, items 3.3.1-64, 3.3.1-66, 3.3.1-130, 3.3.1-131, and 3.3.1-136.

Waterford 3 Response

Each of the Table 2 line items that cite these Table 3.3.1 items credits the Fire Water System Program with the following exceptions.

- The flame arrestor and connecting steel piping (vent lines for the firewater tanks) cite Item 3.1.1-131 with internal environment of outdoor air and credits the Internal Surfaces Monitoring Program. The flame arrestor and vent lines are not subject to flow blockage.

The Fire Water System Program includes provisions to manage flow blockage due to fouling as described in LRA Section B.1.13.

Therefore, the Fire Water System Program manages flow blockage due to fouling for components that cite LRA Table 3.3.1, Items 3.3.1-64, 3.3.1-66, and 3.3.1-130

LRA Table 3.3.1, Item 3.3.1-136 cites loss of material for fire water tanks. Fouling in this line item is not associated with flow blockage.

RAI 3.3.1-3 (FWS AMR-3)

Background:

LRA Table 3.3.1, item 3.3.1-131 addresses steel flame arrestors and piping exposed internally to outdoor air. Loss of material due to general, pitting, and crevice corrosion and flow blockage due to fouling will be managed for these components by the Internal Surfaces in Miscellaneous Piping and Ducting Components program.

Issue:

The staff noted that the Internal Surfaces in Miscellaneous Piping and Ducting Components program proposes to manage the effects of aging for steel flame arrestors and piping through the use of periodic visual examinations of a representative sample of the population of steel components exposed to outdoor air. Flow blockage due to fouling is managed for portions of the fire water systems by periodic visual inspections and tests (e.g., deluge valve tests). While the flame arrestors would not be subject to the specific inspections or tests for flow blockage due to fouling; the LRA does not state the purpose (beyond pressure boundary) of the piping. For example, there is a significant quantity of steel deluge valve piping downstream of the deluge valves that is exposed to outdoor air. Flow blockage due to fouling of the deluge piping is managed by periodically sending water through the pipe. This testing would not be conducted if the aging effects are managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components program.

Request:

State the purpose (e.g., deluge piping) of the steel piping associated with the fire protection system exposed to outdoor air for which aging effects are proposed to be managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components program. If flow blockage due to fouling should be managed for this piping, state the inspections or tests that will be conducted to manage this aging effect.

Waterford 3 Response

The steel fire protection water system piping with internal environment of outdoor air is the vent line to which the flame arrestor is connected. LRA Table 3.3.1, item 3.3.1-131 addresses the flame arrestors and the connected steel vent line piping. The flame arrestors and associated vent line piping are not susceptible to flow blockage due to fouling.

RAI B.1.15-1

Background:

GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," states that that the program "has been shown to be generally effective in managing aging effects in Class 1, 2, or 3 components and their integral attachments in light-water cooled power plants." It provides specific operating experience examples in the "operating experience" program element.

LRA Section B.1.15, Operating Experience section states that, "In January 2010, surface examination for the nozzle-to-top head dome weld was not completed in the second ISI Program Interval as required by ASME Section XI." During the NRC staff's onsite audit, the staff performed a plant-operating experience review and noted that, in addition to missing an item in 2010, the applicant had also missed a Code required examination in 2012. The missed item, related to Line 2RC3/4-56, was documented in NRC Integrated Inspection Report 05000382/2012005.

Issue:

It is not clear to the staff that the program will be effective in managing aging during the Period of Extended Operation (PEO) if Code required examinations are missed.

Request:

Describe programmatic controls that are in place to ensure that the scope of AMP B.1.15 and the ISI IWB, IWC, and IWD inspections are implemented in accordance with requirements of 10 CFR 50.55a.

Waterford 3 Respons

Line 2RC3/4-56 for the reactor pressure vessel head gasket leak-off was scheduled for pressure testing in the first period of the third ISI interval. This exam was not performed at the specified nominal operating pressure due to an error in the procedure. The procedure specified inspection of 2RC3/4-56 with the reactor pressure vessel head installed, which isolates the line from operating pressure.

An evaluation of 2RC3/4-56 subsequently determined the lines did not need inspection based on IWA-1320(e). The error in the pressure test procedure was corrected thereby resolving the reason for the missed examination.

The missed surface examination for the steam generator nozzle-to-top head dome weld in 2012 was the result of an error in the inservice inspection (ISI) database. The ISI database did not include the surface examination as an ASME Section XI required examination. The database was corrected to resolve the reason for the missed examination. An extent of condition review was performed, which concluded that no other code-required examinations were missed. As specified by ASME code, Entergy did perform the required ***volumetric*** examination of the nozzle-to-top head dome weld during the second ISI interval. As part of the condition evaluation, an extent of condition review determined that missing the examination was an isolated incident.

Entergy procedures and the ISI database specify administrative requirements, organizational responsibilities, control and implementation, and exam schedule of the WF3 Inservice Inspection Program. The procedures and the ISI database provide assurance that the requirements of 10 CFR 50.55a will be met.

RAI B.1.30-1

Background:

LRA Table 3.4.2-5-1, “Blowdown System, Nonsafety-Related Components Affecting Safety-Related Systems,” includes accumulators, filter housings, piping, pump casings, valve bodies, and ***tanks*** as component types that will be managed for loss of material using the Periodic Surveillance and Preventive Maintenance program. This is consistent with LRA Drawing G164, Sheet 5, “Flow Diagram Miscellaneous Reactor Auxiliary Systems,” that shows various components, including blowdown tank BD-MTNK-0001 as highlighted and within the scope of license renewal. In contrast, the program description table in LRA Section B.1.30, “Periodic Surveillance and Preventive Maintenance,” states that accumulators, filter housings, piping, pump casings, and valve bodies in the blowdown system will be managed for loss of material. The associated “scope of program” program element states that the program includes the specific components listed in the program description table. In addition, the associated enhancement states that the program procedures will be revised to incorporate the activities listed in the program description table.

Issue:

It is unclear to the staff if tanks in the blowdown system are included within the scope of the Periodic Surveillance and Preventive Maintenance program or if the associated aging effects will be managed by a different program.

Request:

Reconcile the apparent discrepancy between the component types listed in LRA Table 3.4.2-5-1 but not included in the program description table in LRA Section B.1.30, “Periodic Surveillance and Preventive Maintenance,” and update the LRA as appropriate.

Waterford 3 Response

The component type of “tank” is appropriately included in LRA Table 3.4.2-5-1, “Blowdown System, Nonsafety-Related Components Affecting Safety-Related Systems”; however, it was omitted from LRA Section B.1.30, “Periodic Surveillance and Preventive Maintenance,” in the discussion of applicable component types within the blowdown system. The component type “tanks” is added to the program description table in LRA Section B.1.30.

The LRA is revised as follows. Additions are shown with underline.

LRA Sections and Tables Affected

B.1.30 Periodic Surveillance and Preventive Maintenance

Program Description

System	Inspection
Nonsafety-related systems and components affecting safety-related systems, representative samples of abandoned equipment in these systems	Visually inspect the internal surface of piping, filter housings and valve bodies in the radiation monitoring (ARM, PRM) system to manage loss of material. Visually inspect the internal surface of flow elements, piping, sight glasses, traps and valve bodies in the auxiliary steam (AS) system to manage loss of material. Visually inspect the internal surface of accumulators, filter housings, piping, pump casings, tanks, and valve bodies in the blowdown (BD) system to manage loss of material. Visually inspect the internal surface of piping, pump casings, tanks, traps, and valve bodies in the boron management (BM) system to manage loss of material.

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RAI B.1.30-2

Background:

LRA Table 3.3.2-6, “Control Room HVAC System,” shows elastomer ducting being managed for various aging effects, including changes in material properties, by the Periodic Surveillance and Preventive Maintenance program. LRA Section B.1.30 includes a program description table for this program that includes activities to visually inspect the internal and external surfaces of the portable smoke-ejector duct in the control room heating, ventilation and, air conditioning (HVAC) system.

The “parameters monitored or inspected” program element states that polymeric components are inspected for cracking, crazing, scuffing, dimensional changes, discoloration and hardening as evidenced by loss of suppleness. However, the “detection of aging effects” program element only states that established techniques such as visual inspections are used.

Issue:

It is unclear to the staff if physical manipulation will be used to augment visual inspection of the elastomeric portable smoke-ejector duct in the control room HVAC system. The “parameters monitored or inspected” program element states that polymeric components are inspected for hardening as evidenced by loss of suppleness (i.e. physical manipulation). However, the program description table states that the inspection will consist of a visual inspection and the “detection of aging effects” program element states that established techniques such as visual inspections are used, indicating that physical manipulation will not be used to augment visual inspections.

Request:

Clarify whether physical manipulation will be used to augment visual inspection of the elastomeric portable smoke-ejector duct, and if it will be used, then revise the program description table and any corresponding program elements of the Periodic Surveillance and Preventive Maintenance program to reflect this aspect. If physical manipulation will not be used to augment visual inspection of the elastomeric portable smoke-ejector duct, justify the adequacy of a visual inspection to manage the change in material properties.

Waterford 3 Response

Physical manipulation is used to augment visual inspection of the elastomeric portable smoke-ejector duct. Accordingly, LRA Section B.1.30 program description and detection of aging effects program elements are revised.

The LRA is revised as follows. Additions are underlined.

LRA Sections and Tables Affected

B.1.30 Periodic Surveillance and Preventive Maintenance

Program Description

System	Inspection
Control room HVAC	Visually inspect the internal and external surfaces of the carbon steel portable smoke removal fan and elastomeric smoke-ejector duct to manage cracking, loss of material due to wear, and change in material properties. Inspect the smoke-ejector duct while performing physical manipulation of the elastomeric material.

Evaluation

4. Detection of Aging Effects

Periodic surveillance and preventive maintenance activities provide for periodic component inspections and testing to detect aging effects. Inspection and test intervals are established such that they provide timely detection of degradation prior to loss of intended functions. Inspection and test intervals, sample sizes, and data collection methods are dependent on component material and environment, biased toward locations most susceptible to aging, and derived with consideration of industry and plant-specific operating experience and manufacturers' recommendations.

Established techniques such as visual inspections and physical manipulation are used. Each inspection or test occurs at least once every 5 years. Inspections are performed by personnel qualified to perform the selected technique.

For each activity listed above that refers to a representative sample, a representative sample is 20 percent of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components.

RAI B.1.34-1

Background:

LRA Section B.1.34 describes the Reactor Vessel Surveillance Program as an existing program consistent with GALL Report AMP XI.M31, "Reactor Vessel Surveillance." The "detection of aging effects" program element of GALL Report AMP XI.M31 states that the program withdraws one capsule at an outage in which the capsule receives a neutron fluence of between one and two times the peak reactor vessel wall neutron fluence at the end of the period of extended operation and tests the capsule in accordance with the requirements of ASTM E185-82.

GALL Report AMP XI.M31 states that, in accordance with 10 CFR Part 50, Appendix H, an applicant submits its proposed withdrawal schedule for approval prior to implementation. Specifically, III.B.3 of 10 CFR Part 50, Appendix H states that a proposed withdrawal schedule must be submitted with a technical justification as specified in §50.4 and that the proposed schedule must be approved prior to implementation.

During the audit, the staff noted that the applicant identified a need to withdraw and test Capsule 277° at 48 EFPY to represent the fluence exposure for the period of extended operation, as recommended in Reference 4-11 of the LRA (i.e., WCAP-18002-NP, Revision 0, "Waterford Unit 3 Time-Limited Aging Analysis on Reactor Vessel Integrity," July 2015).

Issue:

The staff noted that the applicant did not submit a capsule withdrawal schedule for Capsule 277° for NRC approval in accordance with 10 CFR Part 50, Appendix H. The staff finds that the absence of a staff-approved capsule withdrawal schedule for this capsule is inconsistent with GALL AMP XI.M31.

Request:

Explain why the proposed Reactor Vessel Surveillance Program is consistent with GALL AMP XI.M31 in the absence of a staff-approved withdrawal schedule for Capsule 277°. Alternatively, include in the program submittal of a withdrawal schedule for Capsule 277° to obtain NRC approval in accordance with 10 CFR Part 50, Appendix H.

Waterford 3 Response

The Reactor Vessel Surveillance Program includes establishing a surveillance capsule removal schedule that adheres to the guidance in ASTM E185-82, as required by 10 CFR 50, Appendix H. For the capsule located at 277°, WCAP-18002-NP suggested a removal time of the reactor vessel refueling outage nearest to 48 EFPY. The estimated fluence for the capsule at 48 EFPY is 4.51×10^{19} n/cm^2 providing a fluence greater than the reactor vessel inner radius fluence calculated for 55 EFPY of 4.32×10^{19} n/cm^2.

The WF3 Commitment Management System includes a commitment to submit a reactor vessel surveillance capsule withdrawal schedule for future removal of the capsule located at 277°. The commitment specifies submitting the schedule along with its technical justification for NRC approval.

An engineering change has been initiated to revise the reactor vessel capsule removal schedule for the capsule located at 277° identified in UFSAR Table 5.3-10. In accordance with 10 CFR 50, Appendix H, WF3 will obtain NRC approval of the revised withdrawal schedule before its implementation. The actions described here are consistent with the Program Description of NUREG-1801 XI.M31 “Reactor Vessel Surveillance,” which indicates that a change to the capsule withdrawal schedule must be submitted to the NRC for approval ***prior to implementation***.

<u>RAI B.1.34-3</u>

<u>Background</u>:

Table 3.0-1 of SRP-LR, Revision 2 includes an example FSAR supplement for the summary description of an aging management program consistent with GALL Report AMP XI.M31, “Reactor Vessel Surveillance.” LRA Section A.1.34 describes the FSAR supplement for the applicant’s Reactor Vessel Surveillance Program.

<u>Issue:</u>

In contrast with the FSAR supplement in SRP-LR, Revision 2, the staff noted that LRA Section A.1.34 does not include important attributes of the program

<u>Request:</u>

Justify why the applicant’s FSAR supplement for the program summary description does not include the following important program attributes consistent with the FSAR supplement in Table 3.0-1 of SRP-LR, Revision 2:

a) any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation, and
b) untested capsules placed in storage must be maintained for future insertion.

Alternatively, revise LRA Section A.1.34 to include these program attributes in the FSAR supplement.

<u>Waterford 3 Response</u>

LRA Sections A.1.34 and B.1.34 are revised to include:

a) any changes to the capsule withdrawal schedule, including the withdrawal schedule for spare capsules, must be approved by the NRC prior to implementation, and

b) untested capsules placed in storage must be maintained for future insertion.

LRA revisions are shown as follows. Additions are underlined.

A.1.34 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program manages reduction of fracture toughness and long-term operating conditions for reactor vessel beltline materials using material data and dosimetry. The program includes all reactor vessel beltline materials as defined by 10 CFR 50 Appendix G, Section II.F, and complies with 10 CFR 50, Appendix H for vessel material surveillance.

The objective of the Reactor Vessel Surveillance Program is to provide sufficient material data and dosimetry to (a) monitor irradiation embrittlement at the end of the period of extended operation and (b) establish operating restrictions on the inlet temperature, neutron spectrum, and neutron flux after a surveillance capsule is withdrawn for testing. If surveillance capsules are not withdrawn during the period of extended operation, operating restrictions are specified to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed. Capsules removed from the reactor vessel are tested and reported in accordance with ASTM E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including the withdrawal schedule for spare capsules, must be approved by the NRC prior to implementation. Untested capsules placed in storage must be maintained for future insertion.

B.1.34 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program manages reduction of fracture toughness and long-term operating conditions for reactor vessel beltline materials using material data and dosimetry. The program includes all reactor vessel beltline materials as defined by 10 CFR 50 Appendix G, Section II.F, and complies with 10 CFR 50, Appendix H for vessel material surveillance.

The objective of the Reactor Vessel Surveillance Program is to provide sufficient material data and dosimetry to (a) monitor irradiation embrittlement at the end of the period of extended operation and (b) establish operating restrictions on the inlet temperature, neutron spectrum, and neutron flux after a surveillance capsule is withdrawn for testing. If surveillance capsules are not withdrawn during the period of extended operation, operating restrictions are specified to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed. Capsules removed from the reactor vessel are tested and reported in accordance with ASTM E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Capsules are periodically withdrawn from the reactor vessel in accordance with an NRC-approved withdrawal schedule. One capsule will be withdrawn during an outage in which the capsule receives a neutron fluence of between one and two times the peak reactor vessel wall neutron fluence at the end of the period of extended operation. Any changes to the capsule withdrawal schedule, including the withdrawal schedule for spare capsules, must be approved by the NRC prior to implementation. Untested capsules placed in storage must be maintained for future insertion.

RAI B.1.36-1

Background:

LRA Table 3.3.2-3, "Component Cooling and Auxiliary Component Cooling Water System," includes a single item that only manages loss of material for the wet cooling tower distribution nozzles. The staff notes that the wet cooling tower basins are open to the atmosphere and are susceptible to environmental debris. In addition, the staff notes that the piping upstream of wet cooling tower distribution nozzles is wetted and dried during various operational modes. As discussed in Standard Review Plan – License Renewal, Section 3.2.2.2.5 the wetting and drying of steel components can accelerate corrosion and fouling that could result in plugging of spray nozzles and flow orifices.

Issue:

The wet cooling tower distribution nozzles in LRA Table 3.3.2-3 are not being managed for flow blockage due to fouling. During its audit of the Service Water Integrity aging management program, the staff noted that PM00005814-01 includes inspection of the wet tower distribution nozzles for damage and plugging; however, these activities do not appear to be credited in the LRA through an aging management review item.

Request:

Explain why flow blockage does not need to be managed for the wet cooling tower distribution nozzles, or include a new AMR item to manage this aging effect for these components.

Waterford 3 Response

LRA Sections and Tables Affected

The auxiliary component cooling water (ACC) system takes water from the wet cooling tower basin, pumps it through the component cooling water heat exchanger where its temperature is raised, and then to the wet cooling tower for heat dissipation to the atmosphere. The cooling tower basin filtration system circulates, filters, and chemically treats the water in the basins. The ACC system water chemistry is maintained per site procedures and is less corrosive and contains fewer particulates than typical service water systems.

The cooling tower nozzles are designed to be clog resistant and tolerant of large particulates. WF3 operating history has shown no fouling or blockage issues with these nozzles. The nozzles are visually inspected for damage or clogging on a frequency of once every two years. The inspections performed over the last 10 years identified no issues with fouling or blockage of the nozzles.

EPRI Technical Report 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, indicates that flow restriction may be an issue for spray and sprinkler nozzles, but is not considered an age-related effect. Operating experience has shown that fouling, silting, and corrosion product buildup are short-term effects that can occur well before the end of the initial 40-year license term.

Due to the ACC water quality and the nozzle design, flow blockage is not an aging effect requiring management for the wet cooling tower distribution nozzles. Waterford 3 operating experience supports this conclusion.

<u>RAI B.1.36-2</u>

<u>Background</u>:

Components in the nonsafety-related wet cooling tower chemical addition and filtration system are not within the scope of license renewal. Design Basis Document W3-DBD-4, “Component Cooling Water, Auxiliary Component Cooling Water,” states that “siphon breaker holes” in the suction piping for the wet basin filtration pumps eliminate the potential for inadvertently removing water from the wet cooling tower basins due to pressurized leaks, which could divert the water outside of the basins. The staff notes that the wet cooling tower basins are open to the atmosphere and are susceptible to environmental debris, and the water in the wet cooling tower basins is classified as “raw water.”

<u>Issue</u>:

LRA Section 2.1.1.2 “Application of Criterion for Nonsafety-Related SSCs Whose Failure Could Prevent the Accomplishment of Safety Functions” discusses various aspects associated with functional and physical failures of nonsafety-related components. However, these discussions do not include considerations that would be associated with blockage of the siphon breaker holes as a potential failure in the wet cooling tower chemical addition and filtration system. The “failure” (i.e., plugging) of the siphon breaker holes in the suction piping could occur during normal operation of the associated system without being detected, which could allow inadvertent removal of water from the wet cooling tower basins. It is not clear to the staff that failure (i.e., plugging) of the siphon hole could not prevent satisfactory accomplishment of an auxiliary component cooling water system intended function.

<u>Request</u>:

Explain why the siphon breaker holes in the wet cooling tower chemical addition and filtration system can be excluded from the scope of license renewal or provide aging management review item(s) to manage the effects of aging for the associated components.

<u>Waterford 3 Response</u>

Wet cooling tower basin level instrumentation provides operators with level indication and low level alarms to support the auxiliary component cooling water system intended function. If flow blockage of these anti-siphon holes caused a low level in the basin, the basin level indications and alarms would alert plant staff and allow for corrective action to restore level thereby assuring the basin level remains adequate to support the system license renewal intended functions. The siphon breaker holes in the wet cooling tower chemical addition and filtration system are appropriately excluded from the scope of license renewal.

RAI B.1.36-3

Background:

LRA Section B.1.36, “Service Water Integrity,” includes an enhancement to revise associated program procedures to monitor the auxiliary component cooling water (ACCW) basins for biological fouling by visual inspection as well as analysis of water for biological activity. LRA Section B.1.36 also states that this program manages components as described in the Waterford 3 response to NRC Generic Letter 89-13 [“Service Water System Problems Affecting Safety-Related Equipment”]. Waterford’s response to Generic Letter 89-13, dated January 29, 1990, for Action I states that “LP&L [the prior licensee] monitors the ACCW basins for biological fouling by visual inspection as well as analysis of water for biological activities on a weekly basis.”

Issue:

The staff notes that NEI 99-04, “Guidelines for Managing NRC Commitment Changes,” states “Regulatory commitments may involve new actions as well as existing actions credited by licensees in responding to NRC requests. For example, responses to an item in an NRC bulletin crediting an existing program, practice or plant feature as meeting the intent of the requested action is a regulatory commitment.” Unless Waterford is no longer monitoring the ACCW basins by visual inspection and by analysis of water for biological activity, as stated in Waterford’s response to Generic Letter 89-13, the need for an enhancement to the Service Water Integrity program to do the same thing is unclear to the staff.

Request:

With regard to activities at Waterford 3 related to monitoring ACCW basins for biological fouling, reconcile the need for the current LRA enhancement with regard to the Waterford 3 response to Generic Letter 89-13 dated January 29, 1990.

Waterford 3 Response

Further review of existing site implementing procedures indicates that the enhancement related to monitoring the auxiliary component cooling water (ACCW) basins for biological fouling by visual inspection and sampling is unnecessary. The Service Water Integrity Program as described in LRA Section B.1.36 meets the intent of the actions described in the Waterford 3 response to GL 89-13. The ACCW system visual inspection activities for biofouling described in GL 89-13 are performed every four years. In addition a filtering system cleans the water in the ACCW basins to maintain water chemistry and reduce biofouling. The Waterford 3 actions related to monitoring the ACCW basins by visual inspection are consistent with the program described in NUREG-1801, Section XI.M20.

The wet cooling tower basins were sampled on a weekly basis for biologicals in accordance with industry practice at the time. As the industry improved the methods for monitoring biofouling, Entergy also improved its monitoring practices for monitoring biofouling. This monitoring is consistent with the recommendations of EPRI 1025318, Open Cooling Water Chemistry Guideline, which defines an established approach in the control of biological fouling. Entergy monitors biological fouling by sampling for concentrations of adenosine triphosphate (ATP) and sulfate reducing bacteria (SRB). ATP is monitored on a monthly basis and SRB on a quarterly basis.

LRA Sections A.1.36 and B.1.36 are revised as shown below. Deletions are shown with strikethrough.

LRA Section A.1.36 Service Water Integrity Program

- ~~Revise Service Water Integrity Program procedures to monitor the ACCW basins for biological fouling by visual inspection as well as analysis of water for biological activity.~~

LRA Section B.1.36 SERVICE WATER INTEGRITY

~~3. Parameters Monitored or Inspected~~ ~~4. Detection of Aging Effects~~	~~Revise Service Water Integrity Program procedures to monitor the ACCW basins for biological fouling by visual inspection as well as analysis of water for biological activity.~~

RAI B.1.36-6

Background:

Aging management program evaluation report WF3-EP-14-00010, Revision 0, "Aging Management Review Summary," Section 1.2 states that tables in each aging management review report summarize the results by component type. It also states that the aging management review report results are unchanged in the aging management review summary except for minor editorial changes, with no effect on the results.

Aging management program evaluation report WF3-ME-14-00009, Revision 1, "Aging Management Review of the Component Cooling and Auxiliary Component Cooling Water Systems," Section 4 states that the technical evaluation to demonstrate that the effects of aging will be managed is accomplished by establishing a clear relationship among the components under review, the aging effects being managed, and the credited programs. Section 4.5 states that the One-Time Inspection program will manage loss of material in the carbon steel circulating water intake piping. This is also reflected in the "Aging Management Review Results" table in Attachment 2. In addition, the Attachment 2 table also indicates that the tank in this system is managed for loss of material by the Water Chemistry-Closed Treated Water Systems program.

LRA Table 3.3.2-3, "Component Cooling and Auxiliary Component Cooling Water System," does not show carbon steel piping as being managed by the One-Time Inspection program nor the carbon steel tank as being managed by the Water Chemistry – Closed Treated Water Systems. In addition, LRA Table 3.3.2-3 shows that carbon steel piping with internal coatings will be managed for loss of material and loss of coating integrity by the Coating Integrity program. However, aging management program evaluation report WF3-ME-14-00009, does not list carbon steel piping with internal coatings as a component type in its Attachment 1, "Components Subject to AMR," or Attachment 2, "Aging Management Review Results."

Issue:

The LRA is not consistent with the relevant basis document such that the staff cannot understand what aging effect the piping specified above is subject to or how it will be managed.

Request:

Reconcile the apparent discrepancies discussed in the "Background" section above associated with aging management program evaluation report WF3-ME-14-00009 and LRA Table 3.3.2-3.

Waterford 3 Response

Each of three apparent discrepancies from the Background section of this RAI is addressed as follows.

Item 1

WF3-ME-14-00009, Revision 1, "Aging Management Review of the Component Cooling and Auxiliary Component Cooling Water Systems," indicates that the One-Time Inspection Program will manage loss of material in carbon steel circulating water intake piping. However, LRA Table 3.3.2-3 does not show that the One-Time Inspection Program manages loss of material for carbon steel circulating water intake piping.

Item 1 Response

WF3-ME-14-00009, Revision 1, “Aging Management Review of the Component Cooling and Auxiliary Component Cooling Water Systems,” provides the aging management review results for the component cooling and auxiliary component cooling water systems. A separate topical aging management review report provides aging management review results for components with internal coating or lining. WF3-EP-14-00010, Revision 0, “Aging Management Review Summary,” the AMRS report, reconciles and summarizes the results from system aging management review reports, such as WF3-ME-14-00009, and from aging management review topical reports, such as the WF3 license renewal topical report on coating integrity. The AMRS report shows that carbon steel piping with internal coating in the component cooling and auxiliary component cooling water systems is included in the Coating Integrity Program. Consistent with the AMRS report, LRA Table 3.3.2-3 indicates that the Coating Integrity Program will manage the effects of aging on carbon steel piping with internal coating in the system. As described in LRA Section B.1.4, the Coating Integrity Program includes a one-time inspection of the carbon steel circulating water piping. The AMRS report is the basis document for LRA Table 3.3.2-3 (and all other LRA Summary of Aging Management Evaluation tables). WF3 LRA Table 3.3.2-3 is, therefore, consistent with the relevant basis document.

Item 2

WF3-ME-14-00009, Revision 1, “Aging Management Review of the Component Cooling and Auxiliary Component Cooling Water Systems,” also indicates that the Water Chemistry-Closed Treated Water Systems Program manages loss of material for the tank in this system, while LRA Table 3.3.2-3 does not indicate that the Water Chemistry-Closed Treated Water Systems Program manages loss of material for the tank.

Item 2 Response

WF3-ME-14-00009, Revision 1, “Aging Management Review of the Component Cooling and Auxiliary Component Cooling Water Systems,” provides the aging management review results for the component cooling and auxiliary component cooling water systems. A separate topical aging management review report provides aging management review results for components with internal coating or lining. WF3-EP-14-00010, Revision 0, “Aging Management Review Summary,” the AMRS report, reconciles and summarizes the results from system aging management review reports, such as WF3-ME-14-00009, and from aging management review topical reports, such as the WF3 license renewal topical report on coating integrity. The AMRS report shows that the carbon steel tank with internal coating in the component cooling and auxiliary component cooling water systems is included in the Coating Integrity Program. The only carbon steel tank in LRA Table 3.3.2-3 is the component cooling water surge tank. Consistent with the AMRS report, the Coating Integrity Program will manage the effects of aging on the tank. The AMRS report is the basis document for LRA Table 3.3.2-3 (and all other LRA Summary of Aging Management Evaluation tables). WF3 LRA Table 3.3.2-3 is, therefore, consistent with the relevant basis document.

Item 3

LRA Table 3.3.2-3 shows that the Coating Integrity Program will manage loss of material and loss of coating integrity for carbon steel piping with internal coatings. However, aging management program evaluation report WF3-ME-14-00009, does not list carbon steel piping with internal coatings as a component type in its Attachment 1, “Components Subject to AMR,” or Attachment 2, “Aging Management Review Results.

Item 3 Response

WF3-ME-14-00009, Revision 1, "Aging Management Review of the Component Cooling and Auxiliary Component Cooling Water Systems," provides the aging management review results for the component cooling and auxiliary component cooling water systems. A separate topical aging management review report provides aging management review results for components with internal coating or lining. Carbon steel piping with internal coating is listed as a component type in the coating integrity aging management review topical report; not in WF3-ME-14-00009, the system aging management review report. The AMRS report shows that carbon steel piping with internal coating in the component cooling and auxiliary component cooling water systems is included in the Coating Integrity Program. Consistent with the AMRS report, the Coating Integrity Program will manage the effects of aging on the carbon steel piping with internal coating in the system. The AMRS report is the basis document for LRA Table 3.3.2-3 (and all other LRA Summary of Aging Management Evaluation tables). WF3 LRA Table 3.3.2-3 is, therefore, consistent with the relevant basis document for this item.

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<u>RAI B.1.10-1</u>

<u>Background</u>:

The “detection of aging effects” program element of GALL Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” as modified by LR-ISG-2011-03, “Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2, Aging Management Program XI.M41, ‘Buried and Underground Piping and Tanks,’” and LR-ISG-2012-02, “Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation” states, in part:

> “The entire population of in-scope piping that has tightly adhering insulation is visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections.”

The enhancement to the “detection of aging effects” program element in License Renewal Application (LRA) Section B.1.10, “External Surfaces Monitoring” on page B-45 states, in part:

> “[T]he entire population of in-scope *accessible* piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections.”

<u>Issue</u>:

The GALL Report AMP states that the entire population of in-scope piping components with tightly adhering insulation will be visually inspected, but the enhancement to the applicant’s External Surfaces Monitoring program specifies visual inspection of the “entire population of in-scope *accessible* piping component surfaces that have tightly adhering insulation.” The applicant’s use of the word “accessible” suggests excluding inaccessible components from inspections.

<u>Request</u>:

Describe usage of the term “accessible” in this enhancement and explain why it is adequate.

<u>Waterford 3 Response</u>

No inaccessible components with tightly adhering insulation have been identified at Waterford 3 that are in scope and subject to aging management review for license renewal. Therefore, the term “accessible” will be removed from the enhancement to the External Surfaces Monitoring Program in LRA Section A.1.10 and Section B.1.10.

The LRA is revised as follows. Deletions are shown with strikethrough.

LRA Sections and Tables Affected

A.1.10 <u>External Surfaces Monitoring Program</u>

- Revise External Surfaces Monitoring Program procedures as follows:
- Revise External Surfaces Monitoring Program procedures to provide guidance that removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. However, the entire population of in-scope ~~accessible~~ piping

component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections will not be credited towards the inspection quantities for other types of insulation.

B.1.10 External Surfaces Monitoring

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

4. Detection of Aging Effects	Revise External Surfaces Monitoring Program procedures to provide guidance that removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. However, the entire population of in-scope ~~accessible~~ piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections will not be credited towards the inspection quantities for other types of insulation.

RAI B.1.10-2

Background:

During the July 2016 Aging Management Program (AMP) audit of the Waterford 3 (WF3) License Renewal Application (LRA), recent plant-specific operating experience regarding corrosion on external surfaces of structures and components was reviewed, along with recent site activities to resolve these situations. Review of this information has shown that external corrosion of steel components exposed to an outdoor air environment is a significant issue at WF3. Waterford 3 Licensee Event Report 2014-004-03 states that through-wall corrosion was identified on the Emergency Diesel Generator Feed Tank vent lines where the vent lines pass through the roof. The corrosion was identified by an NRC inspector and it was unknown how long the through-wall corrosion had existed. A fleet procedure change is being developed that could potentially address the plant-specific operating experience.

Issue:

As presented to the staff during the audit, the fleet procedure does not address all components within the scope of license renewal.

Request:

Describe how the fleet procedure will be used to manage aging effects during the period of extended operation.

Waterford 3 Response

The referenced fleet procedure provides guidance for the conduct of system walkdowns of systems, components, and structural commodities. The procedure change discussed in the background of this RAI is the addition of a step to establish written walkdown plans for all Category 1 systems.

The change to establish written walkdown plans is applicable to Category 1 systems (risk significant 10CFR50.65, maintenance rule systems) because of their higher risk significance. While written walkdown plans are not required for non-Category 1 systems, all systems within the scope of license renewal must undergo system walkdown inspections to support aging management programs for plants with renewed licenses. During the period of extended operation, a list of the systems determined to be in scope for license renewal in accordance with 10CFR54.4 and requiring visual inspections shall be maintained by WF3.

Inspections shall include areas surrounding safety-related systems to identify hazards to those systems. Inspections of nearby systems that could impact safety-related systems will include systems, structures, and components (SSCs) that are in scope and subject to aging management review for license renewal in accordance with 10CFR54.4(a)(2).

The fleet procedure is an implementing procedure for the External Surfaces Monitoring Program. Entergy's practice during license renewal implementation activities following receipt of a renewed license is to annotate specific provisions within procedures that are credited for managing the effects of aging. Those annotations indicate that the relevant provisions satisfy regulatory commitments associated with license renewal. These actions ensure that the aging management provisions of the procedure are not changed without following the proper process for managing regulatory commitments.

RAI B.1.10-3

Background:

The “acceptance criteria” program element of GALL Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” as modified by LR-ISG-2011-03, “Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2, Aging Management Program XI.M41, ‘Buried and Underground Piping and Tanks,’” and LR-ISG-2012-02, “Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation” states, in part:

> “For flexible polymers, a uniform surface texture and uniform color with no dimensional change is expected. Any abnormal surface condition may be an indication of an aging effect for metals and for polymers.”

The enhancement to the “acceptance criteria” program element in License Renewal Application (LRA) Section B.1.10, “External Surfaces Monitoring” on page B-46 states, in part:

> “Revise External Surfaces Monitoring Program procedures to include the following acceptance criteria.
>
> […]
>
> - Flexible polymeric materials should have a uniform surface texture and color with no cracks and no *unanticipated* dimensional change, no abnormal surface with the material in an as new condition with respect to hardness, flexibility, physical dimensions, and color.”

Issue:

The GALL Report AMP states that no dimensional change is expected for flexible polymers, but the enhancement to the applicant’s External Surfaces Monitoring program states that “flexible polymeric materials should have […] no unanticipated dimensional change.” The word “unanticipated” was deleted from the AMP in ISG-2012-02. The applicant’s usage of the word in this enhancement suggests that there are anticipated dimensional changes for polymeric materials.

Request:

Describe usage of the word “unanticipated” in this enhancement and explain why it is adequate.

Waterford 3 Response

To be consistent with LR-ISG-2012-02, the WF3 LRA is revised to remove the word “unanticipated” from Appendix A.1.10 and from the enhancement in Appendix B.1.10.

Additions are shown with underline and deletions with strikethrough.

LRA Sections and Tables Affected

Appendix A:

A.1.10 External Surfaces Monitoring Program

- Revise External Surfaces Monitoring Program procedures to include the following acceptance criteria.

  - Stainless steel should have a clean shiny surface with no discoloration.

  - Other metals should not have any abnormal surface indications.

  - Flexible polymeric materials should have a uniform surface texture and color with no cracks and no ~~unanticipated~~ dimensional change, no abnormal surface with the material in an as-new condition with respect to hardness, flexibility, physical dimensions, and color.

  - Rigid polymeric materials should have no erosion, cracking, checking or chalking.

Appendix B:

B.1.10 External Surfaces Monitoring

Enhancements

Element Affected	**Enhancement**
6. Acceptance Criteria	Revise External Surfaces Monitoring Program procedures to include the following acceptance criteria. Stainless steel should have a clean shiny surface with no discoloration. Other metals should not have any abnormal surface indications. Flexible polymeric materials should have a uniform surface texture and color with no cracks and no ~~unanticipated~~ dimensional change, no abnormal surface with the material in an as new condition with respect to hardness, flexibility, physical dimensions, and color. Rigid polymeric materials should have no erosion, cracking, checking, or chalking.

RAI 3.3.2.3.15.4-1

Background:

LRA Table 3.4.1, item 3.4.1-14 addresses steel piping, piping components, and piping elements exposed to steam and treated water, which will be managed for loss of material due to general, pitting, and crevice corrosion using the "Water Chemistry Control – Primary and Secondary" and "One-Time Inspection" programs.

LRA Table 3.3.2-15-4, "Auxiliary Steam System, Nonsafety-Related Components Affecting Safety-Related Systems," states that carbon steel traps, valve bodies, and piping exposed to steam will be managed for loss of material by the "Water Chemistry Control – Primary and Secondary." The subject AMR items ***do not*** cite plant-specific note 301, which states that "[t]he One-Time Inspection Program will verify effectiveness of the Water Chemistry Control - Primary and Secondary Program."

Issue:

It is unclear to the staff if carbon steel traps, valve bodies, and piping exposed to steam will be managed for loss of material by (a) Water Chemistry Control – Primary and Secondary program; or (b) the Water Chemistry Control – Primary and Secondary and One-Time Inspection programs.

Request:

Reconcile the apparent discrepancy regarding the program(s) managing loss of material of carbon steel traps, valve bodies, and piping exposed to steam.

Waterford 3 Response

As indicated in the description of the One-Time Inspection Program, the sample size will be 20 percent of the components in each material-environment-aging effect group up to a maximum of 25 components. Carbon steel traps, valve bodies, and piping exposed to steam are elements of the population from which the sample is selected. Notwithstanding the above, Note 301 was inadvertently omitted from these line items in LRA Table 3.3.2-15-4.

A further review of the LRA tables also identified lines in LRA Table 3.3.2-15-28 where the note was omitted. Note 301 is added to the affected lines as shown below. Additions are underlined.

Table 3.3.2-15-4: Auxiliary Steam System, Nonsafety-Related Components Affecting Safety-Related Systems								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
Piping	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – Primary and Secondary	VIII.A.SP-71	3.4.1-14	C, 301
Trap	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – Primary and Secondary	VIII.A.SP-71	3.4.1-14	C, 301
Valve body	Pressure boundary	Carbon steel	Steam (int)	Loss of material	Water Chemistry Control – Primary and Secondary	VIII.A.SP-71	3.4.1-14	C, 301

Table 3.3.2-15-28: Primary Sampling System, Nonsafety-Related Components Affecting Safety-Related Systems								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
Flex hose	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry Control – Primary and Secondary	VII.E1.A-103	3.3.1-124	C, 301
Piping	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry Control – Primary and Secondary	VII.E1.A-103	3.3.1-124	C, 301
Trap	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry Control – Primary and Secondary	VII.E1.A-103	3.3.1-124	C, 301
Valve body	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry Control – Primary and Secondary	VII.E1.A-103	3.3.1-124	C, 301
Vessel	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry Control – Primary and Secondary	VII.E1.A-103	3.3.1-124	C, 301

<u>RAI 2.1-1</u>

<u>Background</u>:

10 CFR 54.4, “Scope,” states, in part:

(a) Plant systems, structures and components [SSCs] within the scope of this part are –

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions – (i) the integrity of the reactor coolant pressure boundary; (ii) the capability to shut down the reactor and maintain it in a safe shutdown condition; or (iii) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable.

(2) All nonsafety-related systems, structures and components whose failure could prevent satisfactory accomplishment of any of the functions identified in (a)(1)(i), (ii), or (iii) of this section.

<u>Issue</u>:

During the on-site scoping and screening methodology audit, the staff reviewed the license renewal application, license renewal implementing documents and current licensing basis documentation applicable to identifying structures to be included within the scope of license renewal in accordance with 10 CFR 54.4(a). In addition, the staff performed walkdowns of the safety-related nuclear island and reactor building that were included within the scope of license renewal in accordance with 10 CFR Part 54.4(a)(1). The staff determined that the nonsafety-related west side access facility, which is immediately adjacent to, and in contact with, the reactor building was not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

<u>Request</u>:

The staff requests that the applicant provide a basis for not including the nonsafety-related west side access facility within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

If an engineering evaluation or analysis is cited as the basis for not including the west side access facility within the scope of license renewal, indicate how it was performed and documented, and how the evaluation or analysis considers the effects of aging.

If the review of this issue concludes that the west side access facility will be included within the scope of license renewal, describe additional scoping evaluations performed to address the 10 CFR 54.4(a) criteria. List additional SSCs included within the scope of license renewal as a result of the review, structures and components for which aging management reviews were performed, and any additional information related to material and environment combinations. For each structure and component for which aging management reviews were performed, describe the aging management programs to be credited for managing the identified aging effects.

Waterford 3 Response

The west side access facility (WSAF) is a nonsafety-related structure and is not included within the scope of license renewal because it has no intended function for 10 CFR 54.4(a)(1), (a)(2), or (a)(3). As described in Waterford 3 license renewal application (LRA) Table 2.2-5, the purpose of the WSAF is to provide access to the radiologically controlled areas and to provide work space for radiation protection personnel.

The WSAF, a non-seismic structure, is located adjacent to the outside wall of the reactor auxiliary building (RAB) which is part of the nuclear plant island structure (NPIS). The NPIS is discussed in LRA Section 2.4.2. The WSAF is a single-story, three-sided prefabricated steel framed structure supported on its own concrete foundation with the west wall of the RAB serving as the fourth wall. The WSAF is structurally separated from the seismic Category I RAB by a half-inch gap where the wall of the RAB meets the foundation of the WSAF. An approximately six-inch gap separates the columns supporting the WSAF roof from the west wall of the RAB. Non-structural flashing is attached to the RAB wall to seal the gap between the WSAF and the RAB.

The Waterford 3 Seismic Category I structures are designed and constructed in a manner that their intended function would not be affected by failure of adjacent non-seismic structures. The RAB, which is integral to the NPIS, is a Seismic Category I, reinforced concrete structure designed in accordance with NRC "General Design Criteria For Nuclear Power Plants" as specified in Appendix A to 10 CFR Part 50. As such, it has been designed for impact loading attributable to tornado generated missiles. The RAB outer walls, including the wall adjacent to the WSAF, are at least 24-inch thick, reinforced concrete. The relatively low-energy, impact loading imposed on the wall due to a postulated collapse of the WSAF is bounded by the loading from tornado-generated missiles, as described in Final Safety Analysis Report (FSAR) Section 3.3.2.1. As such the potential for deleterious interaction between the WSAF and the RAB is not plausible. Should a failure of the WSAF occur (including failure due to the effects of aging), there would be no loss of a license renewal intended function of the adjacent RAB. Therefore, the WSAF does not fall within the scope of 10 CFR 54.4(a)(2).

No additional in-scope SSCs were identified as a result of this review and, therefore, no additional aging management review is necessary.

RAI B.1.28-1

Background:

LRA Section B.1.28, "One-Time Inspection," states that the one-time program activity will verify the effectiveness of several programs by confirming the insignificance of aging effects by verifying that unacceptable loss of material or cracking is not occurring or is, "so insignificant that a plant-specific aging management program is not warranted."

LRA Section B.1.28 states that the he One-Time Inspection Program will be consistent with the program described in NUREG- 1801, Section XI.M32, “One-Time Inspection.”

The “acceptance criteria” program element of GALL Report AMP XI.M32 “One-Time Inspection” states: “Any indication or relevant conditions of degradation detected are evaluated. Acceptance criteria may be based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. For example, ultrasonic thickness measurements are compared to predetermined limits.”

SRP-LR Section A.1.2.3.6 states that quantitative or qualitative acceptance criteria of the program and its basis should be described and that the criteria should ensure the intended functions are maintained.

Issue:

It is not clear to the staff that these statements related to the “acceptance criteria” program element are consistent because the GALL recommends evaluating any indication while the AMP evaluates significant indications. It is also unclear to the staff how the applicant will determine if an indication is significant.

The staff lacks sufficient information to understand how it will be determined that cracking and loss of material is acceptable or will be so insignificant that intended functions will be maintained during the period of extended operation and an aging management program is not warranted.

Request:

With regard to the “acceptance criteria” program element of the LRA AMP activity, explain how it will be determined that cracking or loss of material found is acceptable or so insignificant that an aging management program is not warranted? Include the acceptance criteria for both stainless steel and concrete structures and components in the explanation that would demonstrate consistency with the corresponding program element of the GALL Report AMP; or justify the exception being taken to the GALL Report AMP.

Waterford 3 Response

As summarized in LRA Section B.1.28, “The One-Time Inspection Program” is a new program that will use inspections and evaluation of inspection results to verify unacceptable degradation is not occurring or is occurring at a rate such that loss of intended function will not occur during the period of extended operation. The program is consistent with the program described in NUREG-1801, XI.M32, which states “The program verifies the effectiveness of an AMP and confirms the ***insignificance*** of an aging effect. Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur, but the data are insufficient to rule it out with reasonable confidence; or (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than generally expected. For these cases, confirmation demonstrates that either the aging effect is not occurring or that the aging effect is occurring very slowly and does not affect the component's or structure's intended function during the period of extended operation based on prior operating experience data."

The issue section of this RAI states "the GALL recommends evaluating any indication while the AMP evaluates significant indications. Actually, the Waterford 3 AMP is consistent with the GALL [NUREG-1801] recommendation. LRA Sections A.1.28 and B.1.28 state "***Any*** indication or relevant condition will be evaluated." This evaluation will determine the significance of each identified indication.

For stainless steel, indications or relevant conditions are the same as those identified for the Internal Surfaces in Miscellaneous Piping and Ducting Components Program described in LRA Section B.1.18. Specifically, a clean, shiny surface is expected with no abnormal surface conditions. Therefore, abnormal surface conditions or the lack of a clean, shiny surface are conditions that warrant evaluation.

Concrete structures are not included in the One-Time Inspection Program. However, reinforced concrete piping in the circulating water system is included. Consistent with NUREG-1801, XI.M32, acceptance criteria may be based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. Confirming the insignificance of an aging effect entails demonstrating that either the aging effect is not occurring or that the aging effect is occurring very slowly and does not affect the component's or structure's intended function during the period of extended operation based on prior operating experience data. The program requires evaluation of indications, if any, observed during the one-time inspection of the circulating water piping.

The intent of specific activities in the One-Time Inspection Program is clarified in the following changes to the program descriptions in LRA Sections A.1.28 and B.1.28. Additions are shown with underline and deletions shown with strikethrough.

LRA Section A.1.28 One-Time Inspection Program

Water Chemistry Control – Primary and Secondary Program	One-time inspection activity will verify the effectiveness of the Water Chemistry Control – Primary and Secondary Programs by confirming that ~~unacceptable~~ cracking, loss of material, and reduction of heat transfer ~~is~~ are not occurring or are occurring at a rate that will not cause a loss of intended function.
Oil Analysis Program	One-time inspection activity will verify the effectiveness of the Oil Analysis Program by confirming that ~~unacceptable~~ cracking, loss of material, and reduction of heat transfer ~~is~~ not occurring or are occurring at a rate that they will not cause a loss of intended function.
Diesel Fuel Monitoring Program	One-time inspection activity will verify the effectiveness of the Diesel Fuel Monitoring Program by confirming that ~~unacceptable~~ loss of material or reduction of heat transfer due to fouling ~~is~~ are not occurring or are occurring at a rate that will not cause a loss of intended function.

Reactor vessel flange leak detection line	One-time inspection activity will confirm that cracking and loss of material are not occurring or are occurring so slowly that they will not affect the component intended function during the period of extended operation. ~~so insignificant that a plant-specific aging management program is not warranted~~.
CW intake piping internals (reinforced concrete portions)	One-time inspection activity will confirm that change in material properties, loss of material, and cracking are not occurring or are occurring so slowly that they will not affect the component intended function during the period of extended operation. ~~so insignificant that a plant-specific aging management program is not warranted.~~

LRA B.1.28 ONE-TIME INSPECTION

Water Chemistry Control – Primary and Secondary Program	One-time inspection activity will verify the effectiveness of the Water Chemistry Control – Primary and Secondary Programs by confirming that ~~unacceptable~~ cracking, loss of material, and reduction of heat transfer ~~is~~ are not occurring or are occurring at a rate that will not cause a loss of intended function.
Oil Analysis Program	One-time inspection activity will verify the effectiveness of the Oil Analysis Program by confirming that ~~unacceptable~~ cracking, loss of material, and reduction of heat transfer ~~is~~ not occurring or are occurring at a rate that they will not cause a loss of intended function.
Diesel Fuel Monitoring Program	One-time inspection activity will verify the effectiveness of the Diesel Fuel Monitoring Program by confirming that ~~unacceptable~~ loss of material or reduction of heat transfer due to fouling ~~is~~ are not occurring or are occurring at a rate that will not cause a loss of intended function.
Reactor vessel flange leak detection line	One-time inspection activity will confirm that cracking and loss of material are not occurring or are occurring so slowly that they will not affect the component intended function during the period of extended operation. ~~so insignificant that a plant-specific aging management program is not warranted~~.
CW intake piping internals (reinforced concrete portions)	One-time inspection activity will confirm that change in material properties, loss of material, and cracking are not occurring or are occurring so slowly that they will not affect the component intended function during the period of extended operation. ~~so insignificant that a plant-specific aging management program is not warranted.~~

RAI 4.1-1

Background:

FSAR Table 3.9-9 identifies that the plant design includes the following large bore (greater than 4 inch nominal pipe size), Class 1 valves in the plant design:

- 8" LPSI (low pressure safety injection) header-to-reactor coolant loop inside containment isolation valves
- 12" safety injection tank outlet check valves,
- 12" safety injection header check valves
- 14" reactor coolant loop shutdown cooling upstream suction isolation valves,
- 14" reactor coolant loop shutdown cooling suction inside containment isolation valves.

FSAR Section 3.9.1.1.2 states that these valves were designed to the applicable requirements in the 1971 Edition of ASME Section III, inclusive of the 1972 Winter Addenda, and were analyzed for the applicable cyclic loading conditions identified in FSAR Table 3.9-3. FSAR Section 5.4.12 also confirms that cyclical loading analyses (i.e., fatigue analyses) for these types of valves were included in the CLB. In addition, fatigue analyses for the Class 1 piping are referenced in FSAR Section 5.4.3.

During the AMP audit (July 25 -28, 2016), the applicant stated that the large bore Class 1 valves are included in the scope of the metal fatigue analysis for the Class 1 piping, as described in LRA Section 4.3.1.7.

Issue:

Although LRA Section 4.3.1.7 references the metal fatigue analysis bases for Class 1 piping in FSAR Section 5.4.3, it does not specifically mention that the metal fatigue analyses (cyclical loading and design transient analyses) for the large bore Class 1 valves are within the scope of the metal fatigue analysis for Class 1 piping components. In addition, LRA Section 4.3.1.7 does not refer to the metal fatigue analysis bases for the large bore Class 1 valves that are described in either FSAR Section 3.9.1.1.2 or FSAR Section 5.4.12. Therefore, the LRA does not clearly identify that the metal fatigue analyses for these valves are TLAAs and are within the scope of the metal fatigue TLAA assessment for Class 1 piping in LRA Section 4.3.1.7.

Request:

Clarify where the metal fatigue TLAA for large bore Class 1 valves is located in the LRA. Amend the LRA accordingly if it is determined that: (a) the LRA needs to be amended to include a new metal fatigue TLAA section for the large bore Class 1 valves or (b) LRA Section 4.3.1.7 needs to be administratively amended to include the large bore Class 1 valves and to reference either FSAR Section 3.9.1.1.2 or 5.4.12.

Waterford 3 Response

Class 1 valve fatigue analyses were evaluated as TLAAs. The TLAA evaluation results described in LRA Section 4.3.1.7 include the results of the evaluation of Class 1 valve fatigue TLAAs. To clarify this, LRA Section 4.3.1.7 and Section A.2.2.1 are amended as shown below to identify the Class 1 valves. Additions are underlined.

4.3.1.7 Reactor Coolant System Class 1 Piping and Valves

The reactor coolant loop piping is discussed in FSAR Section 5.4.3. The hot legs, cold legs and pressurizer surge piping was supplied by the nuclear steam system supplier (NSSS), ABB Combustion Engineering, and controlled by project specifications. As indicated in FSAR Section 3.9.1.1.2, the Class 1 valves were supplied by various manufacturers and are designed for applicable cyclic loading conditions. The Class 1 tributary lines analyses include consideration of location specific transients such as loss of charging and loss of letdown.

Structural weld overlays (SWOL) have been installed on piping for the hot leg surge nozzle, hot leg two-inch drains, and the hot leg shutdown cooling nozzles.

The calculated piping and valve CUFs are less than 1. The transients identified in LRA Table 4.3-1 include the transients that require tracking for the Class 1 piping and valves. The Fatigue Monitoring Program will manage the effects of aging due to fatigue on the reactor coolant system Class 1 piping and valves in accordance with 10 CFR 54.21(c)(1)(iii).

LRA Section A.2.2.1

Reactor Coolant System Class 1 Piping and Valves

The hot legs, cold legs and pressurizer surge piping was supplied by the nuclear steam system supplier (NSSS), ABB Combustion Engineering, and controlled by project specifications. The Class 1 tributary lines analyses include consideration of location specific transients such as loss of charging and loss of letdown.

Structural weld overlays (SWOL) have been installed on piping for the hot leg surge nozzle, hot leg 2 inch drains, and the hot leg shutdown cooling nozzles.

Large bore Class 1 valves described in FSAR Section 3.9.1.1.2 are within the scope of the metal fatigue analysis for Class 1 piping.

The Fatigue Monitoring Program (Section A.1.11) will manage the effects of aging due to fatigue on the reactor coolant system Class 1 piping and valves in accordance with 10 CFR 54.21(c)(1)(iii).

RAI 3.1.1.34-1

Background:

LRA Table 3.1.1, item 3.1.1-34 addresses cracking due to stress corrosion cracking (SCC) in stainless steel or steel with stainless steel cladding pressurizer relief tank and associated components (tank shell and heads, flanges, and nozzles) exposed to treated borated water greater than 60 °C (140 °F). LRA item 3.1.1-34 also refers to the aging management guidance in SRP-LR Table 3.1-1, ID 34 stating that the aging effect is managed by using GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for ASME components, and AMP XI.M2, "Water Chemistry." The LRA further indicates that LRA item 3.1.1-34 is not applicable to the applicant's facility because the pressurizer relief tank is nonsafety-related and is not subject to the requirements specified in ASME Code, Section XI, Subsections IWB, IWC, and IWD.

In addition, LRA Table 3.1.1, item 3.1.1-80 addresses cracking due to SCC for stainless steel or steel with stainless steel cladding pressurizer relief tank and associated components (heads, flanges, and nozzles) which are non-ASME Section XI components exposed to treated borated water greater than 60 °C (140 °F). LRA item 3.1.1-80 also refers to the aging management guidance in SRP-LR Table 3.1-1, ID 80 stating that the aging effect is managed by using GALL Report AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection."

Issue:

The staff noted that LRA Table 3.1.2-5-1 describes detailed management review results (called Table 2 items) for nonsafety-related components affecting safety-related systems in the reactor coolant system. Even though LRA Table 3.1.2-5-1 includes Table 2 AMR items for non-safety-related tanks, these items for tanks do not address aging management of cracking in the pressurizer relief tank. Therefore, additional information is necessary to confirm which Table 2 AMR item is used to manage cracking due to SCC for the pressurizer relief tank.

Request:

Clarify why the AMR results for tanks in LRA Table 3.1.2-5-1 do not address cracking due to SCC for the pressurizer relief tank. As part of the response, clarify which LRA table (e.g., Table 3.1.2-X) includes a Table 2 AMR item used to manage cracking due to SCC for the pressurizer relief tank and associated components.

Waterford 3 Response

The pressurizer relief tank operates at containment ambient temperature which is normally below 140°F. The threshold for stress corrosion cracking in stainless steel is 140°F. Consequently, cracking is not an aging effect requiring management for the pressurizer relief tank.

RAI 3.1.1.80-1

Background:

LRA Table 3.1.1, item 3.1.1-80 addresses cracking due to stress corrosion cracking (SCC) for stainless steel or steel with stainless steel cladding pressurizer relief tank and associated components (heads, flanges, and nozzles) which are non-ASME Section XI components exposed to treated borated water greater than 60 °C (140 °F). LRA item 3.1.1-80 also refers to the aging management guidance in SRP-LR Table 3.1-1, ID 80 stating that the aging effect is managed by using GALL Report AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection."

In addition, LRA Table 3.1.2-3 describes aging management review (AMR) results for reactor coolant pressure boundary (RCPB) components. LRA Table 3.1.2-3 indicates that the following non-ASME Class 1 component types are associated with LRA item 3.1.1-80 and are susceptible to cracking due to SCC: (a) valve body, (b) piping, (c) tubing and (d) flow element.

Issue:

The LRA does not clearly indicate whether these non-ASME Class 1 components are ASME Code Class components that are subject to the existing periodic inservice inspections specified in ASME Code, Section XI. Additional information is necessary to clearly identify aging management activities for these non-ASME Class 1 components.

Request:

Clarify whether the non-ASME Class 1 components (valve body, piping, tubing and flow element) discussed above are ASME Code Class components (e.g., ASME Code Class 2 or 3 components) subject to the existing periodic inservice inspections. If so, justify why the LRA does not identify the periodic inservice inspections in the aging management review results for these components.

Waterford 3 Response

The non-ASME Class 1 components represented by the valve body, piping, tubing and flow element line items in LRA Table 3.1.2-3 represent Class 2, Class 3 and non ASME Section XI components that are less than 4 inch NPS and are not subject to periodic volumetric or surface examination under the Inservice Inspection Program.

To minimize potential confusion by the comparison to non-ASME Section XI components in the NUREG-1800 (SRP-LR) line item represented in LRA Table 3.1.1 item 3.1.1-80, the NUREG-1801 item comparisons for these components are revised in Table 3.1.2-3 as shown below.

Additions are shown with underline and deletions with strikethrough.

Table 3.1.2-3: Reactor Coolant Pressure Boundary								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
Flow element (non-Class 1)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry Control – Primary and Secondary	~~IV. C2.RP-383~~ V.A.E-12	~~3.1.1-80~~ 3.2.1-20	C, 101
Piping, (non-Class 1)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry Control – Primary and Secondary	~~IV. C2.RP-383~~ V.A.E-12	~~3.1.1-80~~ 3.2.1-20	C, 101
Tubing (non-Class 1)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry Control – Primary and Secondary	~~IV. C2.RP-383~~ V.A.E-12	~~3.1.1-80~~ 3.2.1-20	C, 101
Valve body (non-Class 1)	Pressure boundary	Stainless steel	Treated borated water >140°F (int)	Cracking	Water Chemistry Control – Primary and Secondary	~~IV. C2.RP-383~~ V.A.E-12	~~3.1.1-80~~ 3.2.1-20	C, 101

RAI 3.1.1.81-1

Background:

LRA Table 3.1.1, item 3.1.1-81 addresses cracking due to stress corrosion cracking (SCC) for stainless steel pressurizer spray head exposed to reactor coolant, which is managed by the One-Time Inspection Program and Water Chemistry Program. During its review of components susceptible to SCC, the staff noted that LRA Section 2.3.1.3 (Page 2.3-14) indicates that reactor coolant pump (RCP) thermal barrier heat exchanger tubes are part of reactor coolant pressure boundary and are subject to aging management review.

The staff also noted that Waterford Unit 3 UFSAR Section 5.2.5.1.5, "Heat Exchanger" indicates that leakage of reactor coolant through the RCP thermal barrier can be detected by the monitoring of component cooling water radiation and surge tank level.

Issue:

The RCP thermal barrier heat exchanger tubes maintain the integrity of reactor coolant pressure boundary. However, the LRA does not clearly identify which AMR item is used to manage cracking in these heat exchanger tubes. In addition, the LRA does not address whether applicant's operating experience confirms that cracking is not occurring in these heat exchanger tubes.

Request:

Clarify which AMR item is used to manage cracking for the RCP thermal barrier heat exchanger tubes. In addition, clarify whether applicant's operating experience, including the component cooling water monitoring activities specified in the UFSAR, confirms that cracking is not occurring in these heat exchanger tubes.

Waterford 3 Response

The RCP thermal barrier heat exchanger is represented in Table 3.1.2-3 by the component type "Heat exchanger – water jacket (seal heat exchanger)." The heat exchanger does not use tubes. The heat exchanger is configured as a series of concentric interlacing baffle plates (fixed and rotating) that form flow channels for the reactor coolant and component cooling water. Heat transfer is across the fixed plates. The operating experience review found no evidence of cracking in these plates.

RAI 4.3.1-1

Background:

LRA Table 4.3-1 provides the list of transients that will be monitored by the Fatigue Monitoring Program. This table includes the number of cycle occurrences, 60-year projected number of cycles, and the analyzed cycle limit.

The LRA states that FSAR Table 3.9-3, “Transients and Operative Conditions for Code Class 1 Non-NSSS Piping,” lists the transients used as inputs to the piping stress analyses.

Both tables include the transient, “Loss of Charging,” as a transient that was used in the stress analyses and will be monitored during the period of extended operation by the Fatigue Monitoring program.

Issue:

FSAR Table 3.9-3 states that the cycle limit of the “Loss of Charging” is 100. LRA Table 4.3-1 states that the cycle limit of this transient is 200. The staff is concerned that the applicant will not monitor the most conservative cycle limit that was used in the stress analyses.

Request:

Clarify the discrepancy between the two cycle limits. Justify that the Fatigue Monitoring Program will ensure that the cycle limits of these analyses will not be exceed during the period of extended operation.

Waterford 3 Response

The FSAR Table 3.9-3 lists 100 cycles for loss of charging because that was the value originally used in the WF3 piping analyses. The piping analysis of record uses the value of 200 cycles for loss of charging as identified in LRA Table 4.3-1. An engineering change has been initiated to correct FSAR Table 3.9-3 to match the value shown in LRA Table 4.3-1 for the loss of charging cycle limit.

RAI 4.3.2-1

Background:

LRA Section 4.3.2.3 discusses the Non-Class 1 Heat Exchangers with Fatigue Analysis. The LRA states that a fatigue analysis was completed for the Class 2 portions of the letdown and regenerative heat exchangers. The LRA states that the cycle limits for these analyses are represented in LRA Table 4.3-1 and will be monitored by the Fatigue Monitoring Program. The applicant dispositioned these fatigue analyses in accordance with 10 CFR 54.21(c)(1)(iii).

Issue:

The LRA did not clarify which transients are used as inputs for the fatigue analyses of the Class 2 portions of the letdown and regenerative heat exchangers. The staff is unclear if these transients are within the scope of the Fatigue Monitoring Program.

Request:

Identify which transients were used in the fatigue analyses of the Class 2 portions of the letdown and regenerative heat exchangers. Confirm that these transients will be monitored under the Fatigue Monitoring Program.

Waterford 3 Response

As described in LRA Section 4.3.2.3 the letdown and regenerative heat exchangers are in the Class 2 portion of the chemical and volume control system. The fatigue analyses for these components used the following transients.

- Plant loading 5%/minute; step increase 10%
- Plant unloading 5%/minute; step decrease 10%
- Maximum purification
- Loss of load-reactor trip
- Loss of charging
- Loss of letdown

As identified in LRA Section 4.3.1, an evaluation was performed to determine the cycles that required tracking. The evaluation of the transient cycles determined some transients did not require counting because the allowable number of cycles will not be exceeded during the period of extended operation (PEO).

The plant loading and unloading step changes were evaluated for 17,000 cycles. The analysis of plant loading and unloading determined the existing analysis is valid for the PEO because WF3 operates as a base-loaded plant.

The maximum purification transient was evaluated for 11,000 cycles. Based on a review of plant data, this event has occurred approximately 200 times in 14 years. The projected value for 60 years of operation would be approximately 858 cycles.

The reactor trip, loss of charging, and loss of letdown transients are tracked as shown in LRA Table 4.3-1 as part of the Fatigue Monitoring Program.

RAI 4.3.3-1

Background:

LRA Section 4.3.3 discusses the applicant's evaluation of the effects of the reactor water environment on fatigue life. The LRA states that environmental screening evaluations were performed for the sample set of Combustion Engineering components provided in NUREG/CR-6260. The LRA states that using bounding environmental correction factors (F_{en}), two locations have a projected 60-year environmentally-adjusted cumulative usage factor (CUF_{en}) greater than the design limit of 1.0. The LRA further states that for these two locations, refined environmental evaluations will be performed prior to the period of extended operation as part of the Fatigue Monitoring Program.

Issue:

The LRA does not provide enough information on how the bounding F_{en} values were calculated. The staff is unclear how the applicant will ensure that these F_{en} values will remain bounding for the period of extended operation. The staff is also unclear what refinement methods will be used for the CUF_{en} evaluations.

Request:

a) Describe how the bounding F_{en} values were determined for evaluating the NUREG/CR-6260 locations for environmental fatigue. Justify how it will be assured that the variables and inputs for these F_{en} values will remain bounding throughout the period of extended operation.

b) Describe what method(s) will be used to refine the CUF_{en} evaluations. Justify that the refinements will be appropriate.

Waterford 3 Response

It was determined that vendor support is necessary to provide a proper response to this RAI. It is anticipated that the response to RAI 4.3.3-1 will be included with the submittal of the Set 3 RAIs.

RAI 3.1.1.74-1

Background:

LRA Table 3.1.1, item 3.1.1-74 addresses wall thinning due to flow accelerated corrosion (FAC) in steel steam generator upper assembly and separators including feedwater inlet ring and support exposed to secondary feedwater or steam. LRA item 3.1.1-74 also refers to the aging management guidance in SRP-LR Table 3.1-1, ID 74 stating that the aging effect is managed by using GALL Report AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry." LRA item 3.1.1-74 further states that the steel feedwater piping components of the Waterford Unit 3 replacement steam generator are composed of alloy steel (Cr-Mo) which is resistant to FAC.

GALL Report AMP XI.M17, "Flow-Accelerated Corrosion" states that the Nuclear Safety Analysis Center (NSAC)-202L-R2 or R3 provides general guidelines for the FAC program. The staff noted that Section 4.2.2 of NSAC-202L-R2 indicates that stainless-steel piping, or low-alloy steel piping with nominal chromium content equal to or greater than 1.25 percent is resistant to FAC.

Issue:

The LRA does not describe a sufficient technical basis for the applicant's claim that the replacement steam generator feedwater piping components are resistant to FAC (e.g., chromium content of the Cr-Mo steel).

Request:

Provide information to demonstrate that the steel feedwater piping components are resistant to FAC (e.g., chromium content of the alloy steel to support material resistance to FAC). If the chromium content of the alloy steel used to fabricate these components is below the threshold described in NSAC-202L-R2 (1.25 wt. percent), provide justification for why these feedwater piping components are resistant to FAC.

Waterford 3 Response

Feedwater piping components exposed to secondary feedwater or steam in the steam generators are fabricated from alloy steel with a chromium content of 1.25% or greater. In accordance with Section 4.2.2 of NSAC-202L-R2, stainless-steel piping or low-alloy steel piping with nominal chromium content equal to or greater than 1.25 percent is resistant to flow accelerated corrosion.

RAI B.1.24-1

Background**:**

The applicant stated in LRA AMP B.1.24 and WF3-EP-14-00009, “Aging Management Program Evaluation Results” that periodic manhole inspections will be performed to assess that cable and cable support structures are intact. The applicant proposed an exception to the “preventive actions” program element, that the inspection frequency will not be increased if water is found in the manholes during periodic manhole inspections. The applicant further stated that because of the elevation of the plant site and manholes, water cannot be prevented from entering the manholes. The applicant concluded that manhole inspections will assess cable and support damage due to exposure to significant moisture, and periodic testing will provide reasonable assurance that each cable will continue to perform its intended function through the period of extended operation. The in-scope inaccessible cables identified by the applicant are the 480V power cables for the electric motor-driven fire pump and the electric motor-driven jockey fire pump.

In addition to periodic testing, GALL Report AMP XI.E3, “Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements” program element “preventive actions” recommends that periodic actions are taken to prevent inaccessible power cables from being exposed to significant moisture, such as identifying and inspecting accessible cable conduit ends and cable manholes for water collection, and draining the water, as needed. In addition, GALL Report AMP XI.E3 also recommends that the inspection frequency for water collection is established and performed based on plant-specific operating experience with cable wetting or submergence in manholes (i.e., the inspection is performed periodically based on water accumulation over time and event driven occurrences, such as heavy rain or flooding). GALL Report AMP XI.E3 further recommends that if water is found during inspection (i.e., cable exposed to significant moisture), corrective actions are taken to keep the cable dry and to assess cable degradation.

GALL Report AMP XI.E3 also notes that when an inaccessible power cable (greater than or equal to 400 volts) is exposed to wet, submerged, or other adverse environmental conditions for which it was not designed, an aging effect of reduced insulation resistance may result, causing a decrease in the dielectric strength of the conductor insulation. This can potentially lead to failure of the cable’s insulation system.

GALL Report AMP XI.E3 further states that in addition to the necessary periodic actions to minimize the potential for insulation degradation, in-scope power cables exposed to significant moisture are tested to indicate the condition of the conductor insulation (including trending of degradation where applicable). The specific type of test performed is determined prior to the initial test and is a proven test for detecting deterioration of the insulation system due to wetting or submergence.

Issue:

It is not clear to the staff that with the proposed exception to the GALL Report AMP XI.E3, “preventive actions” program element that the applicant’s Non-EQ Inaccessible Power Cable (≥400 V) program will provide adequate aging management of the in-scope inaccessible power cables such that both pumps will perform their intended functions during the period of extended operation. The staff’s concern is that without manhole and cable inspections adjusted for water accumulation over time as recommended by GALL Report AMP XI.E3, the in-scope inaccessible power cables may experience increased aging degradation which could potentially lead to failure of the cable’s insulation system.

Request:

Demonstrate that with inspection frequencies not based on water accumulation over time such that periodic actions are not taken to prevent inaccessible power cables from being exposed to significant moisture (i.e., inspecting cable manholes for water accumulation, and draining the water, as needed to limit cable exposure to significant moisture) that the electric motor driven fire pump and electric motor driven jockey pump cable aging effects will be adequately age managed such that both cables will continue to perform their intended functions during the period of extended operation.

Waterford 3 Response

As stated in NUREG-1801, Section XI.E3, when an inaccessible power cable (greater than or equal to 400 volts) is exposed to wet, submerged, or other adverse environmental conditions, an aging effect of reduced insulation resistance may result, causing a decrease in the dielectric strength of the conductor insulation. The program description in Section XI.E3 acknowledges that periodic inspection and water removal actions "are not sufficient to ensure that water is not trapped elsewhere in the raceways. For example, (a) if a duct bank conduit has low points in the routing, there could be potential for long-term submergence at these low points; (b) concrete raceways may crack due to soil settling over a long period of time; (c) manhole covers may not be watertight; (d) in certain areas, the water table is high in seasonal cycles, so the raceways may get refilled soon after purging; and (e) potential uncertainties exist with water trees even when duct banks are sloped with the intention to minimize water accumulation." Therefore, as stated in NUREG-1801, Section XI.E3, in-scope power cables exposed to significant moisture are tested to indicate the condition of the conductor insulation (including trending of degradation where applicable). Under Detection of Aging Effects, Section XI.E3 indicates that a 6-year interval for cable testing "is an adequate period to monitor performance of the cable and take appropriate corrective actions since experience has shown that although a slow process, aging degradation could be significant."

The WF3 aging management program is testing the cables exposed to significant moisture at least once every six years, which will provide an indication of the condition of the cable insulation properties. And, as stated in LRA Section B.1.24 and the site aging management program evaluation document, test frequencies will be adjusted based on test results (including trending of degradation where applicable) and operating experience. Therefore, if cable system degradation is detected, the test frequency is increased, as appropriate.

The 480V electric-driven fire pump and electric-driven jockey fire pump cables are non-1E, nonsafety-related cables. The cables are routed in raceways with manholes or handholes that are not safety-related. There are no splices in these underground cables and there is no history of water treeing in cables that operate at less than 2 kV. Manhole inspections will assess cable and cable support damage, if any, due to exposure to significant moisture, and periodic cable testing will provide reasonable assurance that each cable will continue to perform its intended function during the period of extended operation.

RAI B.1.26-1

Background**:**

WF3-EP-14-00009, “Aging Program Evaluation Results” – Electrical, Section 3.5.B.3.b, “Comparison to WF3 Parameters Monitored or Inspected” states that a representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket and connection insulation surface anomalies indicating signs of reduced insulation resistance. This document further states that this sample of accessible cables will represent, with reasonable assurance, all cables and connections in an adverse localized environment.

Issue:

The use of a representative sample of accessible insulated cable and connections as described in WF3-EP-14-00009 does not agree with the applicant’s LRA AMP or GALL Report AMP XI.E1, “Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Requirements.” Instead, the applicant’s LRA AMP as well as GALL Report AMP XI.E1, call for visual inspection of all accessible insulated cables and connections as an acceptable component sampling to cover accessible and inaccessible cables and connections in an adverse localized environment.

It is not clear to the staff that the applicant’s “Non-EQ Insulated Cables and Connections Program” will be consistent with the GALL Report because the applicant’s aging management program evaluation for the “Parameters Monitored or Inspected” program element describes the applicant’s program as utilizing a representative sample of accessible insulated cables and connections.

Request:

Clarify the WF3-EP-14-00009, “Aging Program Evaluation Results” – Electrical, Section 3.5.B.3.b, “Comparison to WF3 Parameters Monitored or Inspected” program representative sample approach as compared with the GALL Report AMP XI.E1 and LRA AMP B.1.26 recommendation that all accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable jacket and connection insulation surface anomalies indicating signs of reduced insulation resistance.

Waterford 3 Response

NUREG-1801, Section XI.E1, Element 3 states, “Accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable jacket and connection insulation surface anomalies indicating signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation, and moisture intrusion as indicated by signs of embrittlement, discoloration, cracking, melting, swelling or surface contamination.” This statement is by definition a sample, because this is stating that out of all the electrical cables in an adverse environment including accessible and inaccessible, the accessible electrical cables in that adverse environment are to be inspected. The site aging management program evaluation document intent was to enforce that statement. The description for this program in LRA Sections A.1.26 and B.1.26 provides a better description for this concept.

LRA Section B.1.26 states, “Accessible insulated cables and connections within the scope of license renewal installed in an adverse localized environment will be visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination, indicating signs of reduced insulation resistance. The program sample consists of all accessible cables and connections in localized adverse environments. This program sample of accessible cables will represent, with reasonable assurance, all cables and connections in the adverse localized environment."

Waterford 3 license renewal commitment 21 is to implement the program described in LRA Section B.1.26. The program description in LRA Section B.1.26 appropriately characterizes that the inspection will include all accessible cables in adverse environments. Entergy plans to revise WF3-EP-14-00009, "Aging Program Evaluation Results" – Electrical, Section 3.5.B.3.b to clarify that the intent is consistent with the B.1.26 program description.

Enclosure 2 to

W3F1-2016-0069

Table 3.4.2-4 Correction
Waterford 3 License Renewal Application

Table 3.4.2-4 Correction

The Waterford 3 License Renewal Application (LRA) Table 3.4.2-4 Main Steam System (MS) includes a carbon steel valve with a treated water (internal) environment. Only one valve was included in the main steam system for which this material and environment were assigned, specifically, a valve associated with the Waterford 3 emergency feedwater (EFW) pump bearing cooler. This valve was subsequently determined to have been fabricated from stainless steel. LRA Table 3.4.2-4 is revised as shown below to correct the material designation and the aging management review results.

Deletions are shown with strikethrough and additions are underlined.

Table 3.4.2-4
Main Steam System
Summary of Aging Management Evaluation

Table 3.4.2-4: Main Steam System								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG -1801 Item**	**Table 1 Item**	**Notes**
Valve body	Pressure boundary	~~Carbon steel~~ <u>Stainless steel</u>	Treated water (int)	Loss of material	Water Chemistry Control – Primary and Secondary	~~VIII.B1. SP-74~~ <u>VIII.G. SP-87</u>	~~3.4.1-13~~ <u>3.4.1-16</u>	A, 401